STAFF WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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| In the Matter of: | ) | |
| | ) | Docket No. |
| NATURAL GAS SUPPLY AND | ) | |
| INFRASTRUCTURE ASSESSMENT | ) | |
| | ) | |

CALIFORNIA ENERGY COMMISSION

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HEARING ROOM A

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P R O C E E D I N G S

9:45 a.m.

MR. MAUL: We'd like to get started here. We appreciate your showing up here on a foggy morning here in Sacramento and a Friday. Probably you would love to be home or traveling or someplace else. But we're glad that you're here with us today. So we'd like to welcome you all here today.

My name is David Maul; I'm the Manager of the Natural Gas and Special Projects Office here at the Energy Commission. I'd like to welcome you here to our workshop. This is a staff workshop on our natural gas supply and infrastructure assessment report.

Before we get started I'd like to just do a few quick housekeeping things. First, does everybody have an agenda for today's event? They're out on the front table. If you don't, raise your hand and we'll pass it out to you right now. Make sure you keep track of what's going on.

Hopefully we'll keep on schedule today. We would like to respect your valuable time and try to get you out of here by 4:00 today. So, we'll try to march through here as efficiently as we can.

But I do want to highlight that we are here to not only present information to you in exploring the reports that we have, but more importantly, we're here today to get information from you. So we have a number of questions that we've posted on the web that we had asked you to think about in advance beforehand. And we'd like you to ask as many questions as you can and offer as much insight as you can from your perspectives in the natural gas industry, and on the report that we have today.

So, please feel that this is more of a seminar format, this is a discussion format, this is not I'm-going-to-stand-here-and-talk-to-you-the-entire-time format. This will be very interactive hopefully.

Secondly, I'd like to compliment our staff that helped put this together. Jairam Gopal, Jairam, raise your hand, is the Supervisor of our natural gas unit and the leader of this particular report. Jairam and his staff have done a marvelous job pulling this together, doing the analysis. And he's in the middle of now doing the next round of analysis. So any guidance that you can provide to us today will help Jairam and our gas staff in their modeling efforts to pull this together.

They also were assisted by our report-writing team, Mignon Marks and Bob Logan. Let's see, where's Bob? I saw Bob earlier -- there's Bob Logan. So, the document you saw, hopefully, is a nice looking document in part due to their credits.

So, with that, -- also I'd like to note that in the spirit of cooperation, and actually as far as efficiency goes, we're working very closely with our colleagues at the California Public Utilities Commission. And I think Rich Meyer and Sapida -- where's Rich? There's Sapida and there's Rich here someplace. We're working closely with them. And it's our goal, within government, to make sure that we have no secrets; that any information we have they have, so that we can move forward as efficiently as possible to serve the public and the State of California.

So, with that I'd like to turn it over to Jairam Gopal to lead today's workshop. And thank you, again, for coming.

DR. GOPAL: Thank you, Dave, and

welcome, everyone. It's a beautiful morning in Sacramento.

(Laughter.)

DR. GOPAL: Someone said they brought the sunlight here, but I still don't see it, so they better hurry.

All right. In order to get started I think one of the things that Dave did mention was that he told you to ask a lot of questions. I have one more request. Answer a lot of questions, too. So I'm looking for questions, but I'm looking for answers, too, because they are the critical drivers that will be taking us through the next cycle in analysis.

Let me just briefly go over what we're going to do here, what are the things that we need to observe, et cetera, et cetera.

Cell phones can be turned off if you don't want to hear it.

(Laughter.)

DR. GOPAL: All right, basically I'm going to introduce the staff members and Dave has already started the process; I'll continue with that.

The other thing that we want to do today is get your comments and input on the 2002 assessment paper that was on the Website. And I believe you have all read it, because you're all here in full force.

The third point, discussion on relevant and critical issues. We want to make sure that we get every critical issue put on the table so that we can start thinking, analyzing and trying to see how we can address the market comprehensively.

And finally, the last point here, the questions and answers that I need. You have seen the questions and we will try, and either staff will answer some, or we will be looking to you to get the answers.

Today's agenda. The first we will start off with Mignon presenting the demand assumptions and assessments that we have in our paper. That will be followed by Leon Brathwaite, who will talk about the supply side assumptions in the model. He will also provide a very, very, very brief discussion on what the model is and how we use it. For a more detailed discussion probably we can do it later on.

Depending on how the timing is we will either take the lunch break then, or we will discuss prices. That session will be led by Todd Peterson.

After prices, of course, now that we have the supply demand and price picture all set, we will see what happens in the marketplace. That infrastructure session will be led by Bill Wood.

And finally, given all these, we still have this big question mark, the uncertainty of future, you know, who's going to do what, who's going to pay whom, et cetera, et cetera. And that discussion on risk and reliability assessment will be led by Bob Logan.

You're all free to ask questions during the sessions. Now, after the demand session I will call a few people who will serve as a panel today to help us in focusing questions, answering questions and taking the discussion forward.

I hope you all signed in at the front. I want to make sure I get your phone numbers and e-mails. E-mail is the particular detail that I really need. That's the only form of communication I believe in.

You're not supposed to read this slide, because I'm sure you already have read it, you've got it in your mind, and you got the answers ready for me.

The first bullet, natural gas is plentiful. How many times have you heard it? A thousand times. And even today you will hear it a thousand times, but then still the price is high. So that's one big issue that we should be tackling.

You know that crude reserves have continued to maintain their levels, so that doesn't seem to be the big issue. Short-term seasonal aspects, power generation, of course, they are driving the gas prices demand/supply situation, and the infrastructure analysis. So we will be getting a lot into it.

Skip the next bullet. We still want to do it on an annual basis. That's what we're trying to do to make sure that you get the information in a very timely manner.

I want to continue with the next one. We do a continent-wide analysis to make sure that we address this integrated market in sufficient detail.

And finally, we need to look at the energy climate, which means not just the energy supply/demand but also the financial side, the credit worthiness; the mindset of the industry, itself, is something that we need to capture in our analysis to make sure that we get a better look into the future.

Integrated gas marketplaces, what we want to do. Interconnected pipelines, I think you know this, but have talked about it so many times before.

We've always talked about the low gas prices for the last ten years because we had a very big gas bubble. And suddenly that bubble burst, too.

The other issues that we are interested in now, you know, an analysis, electricity, restructuring has made a lot of changes. We're trying to address how to capture some of those issues.

Natural gas electricity convergence. Is it a new paradigm? Is it going to take us somewhere else, away from what we have been thinking in the past? That's one issue that we would like to address.

And finally, electric generation. There is a race, you know, it's the tortoise, is it the hare, who's going to win? Who's going to come on front, and how do we deal with that?

So, those are the basic, the changes that we have to deal with in our new report.

In our analysis, I will skip this slide because throughout this day we will be talking about the various drivers that we will be dealing with.

And finally, your comments are most welcome. Documentations, the documents that have been presented here will be posted on the Website at a later date. I know that all of you may not have your answers right now, so I'm going to give you more time. February 3rd, close of business; it's a Monday. If that's a problem, please let me know.

And finally, of course we will have a panel set up today later on, who is going to help us, guide us, et cetera.

Okay, I now will call upon Mignon to make a presentation on the demand side of the paper.

MS. MARKS: Hi, everybody. I'm Mignon Marks and I'm actually new to the natural gas area, so they gave me more of the editing assignment part of the report preparation. But I did also author the demand chapter based on information collected by the Energy Commission and the Gas Research Institute and the Canadian Energy -- CERI, whatever that is, let's see, it's the Canadian Energy Research Institute.

I have asked Lynn Marshall and David Vidaver to be in the audience today. They're responsible for the California gas demand and supply forecast related to natural gas, so they'll be here. And David Vidaver, in particular, will be helping me close out my presentation on the demand chapter.

What I'd like to do is really to summarize what's in the demand chapter and then give you an indication of what the plan is for doing the next demand forecasts.

The demand forecast for the United States was based on data from the Gas Research Institute's baseline projection databook that was published in the year 2000.

And you'll see here that what GRI was predicting was going to happen for the five end use sectors from 1995 to the year 2015, you see here on the bottom that the commercial and residential demand growth is relatively slow.

Industry remains the largest gas consumer. Natural gas vehicles gain market share over time.

But the biggest impact in gas demand will come from electricity generation. Also note that GRI was predicting that gas demand would reach, you know, approximately 30 Tcf, trillion cubic feet, by the year 2015.

These two graphs illustrate numerical data that was provided in table 1 in the report. I've graphed demand growth in the four subregions of the WECC separately, first for electric generation only, and then for all other end use sectors.

Note that the southwest, this red band here, is expected to become the second largest gas-using region due to additions in gas-fired electric generation. Demand growth in all other sectors is less dramatic.

This graph illustrates projected output by both new and existing electricity generators in the western United States, assuming average weather conditions and hydro electricity availability.

Note that the output of natural gas-fired generators, this is the red line here, is predicted to surpass the output of all other types of electricity generators by the year 2006. But these projections were done before the dropoff in a significant number of electric plants, and also it's before California adopted the renewable portfolio standard. And David Vidaver will be telling us a little bit more about his plans to update these projections.

This slide provides a breakout of the expected electricity generation additions in the western United States by subregion and over time. Electric generation additions were expected to total more than 46,000 megawatts by the year 2012. The stacked bar chart on the right provides you a breakout over time, and also by subregion in the WECC.

And what you'll see here is, first, that two-thirds of the estimated growth was expected to occur in the California, northern Mexico and southwest regions. And then also that the majority of the growth was expected, two-thirds of the growth was expected to occur in the first few years of the forecast period.

This graph shows California total gas demand on both utility-served loads as well as loads that are served directly by in-state producers and by imports from the Kern River and Mojave interstate pipeline systems.

By 2012 the staff projected that annual average -- sorry, wrong page -- this is for both utility as well as non-utility loads. And you'll see that on the far right here that gas demand was expected to reach 7.5 billion cubic feet per day, and that the electric generation sector is projected to have about a 2 percent per year growth rate.

And this graph illustrates the data that was provided in appendix A. And what I've done is I've separated California gas demand into core, non-core and electric generation sectors. And relative to the 1997 base year, core customers are expected to have the largest volume increase, but electricity generation places a close second.

This graph illustrates that new, more efficient, gas-fired units are expected to displace approximately two-thirds of the natural gas used by steam turbine generators, as well as to serve new load, electric load.

(Off-the-record discussion.)

MS. MARKS: There we go, thank you. So

our plans are to produce another forecast of gas supply, price and infrastructure in the spring of this year. And this time we will be using demand data for the U.S. from the EIA, USEIA, rather than from the Gas Research Institute.

Our natural gas demand forecast will be part of the integrated energy policy report work that's being done by the Commission. And we expect to have the next demand forecast published by February the 11th. And then there'll be another staff workshop on February the 25th to go over these demand forecasts.

I'd like to now ask David Vidaver, if he has time, about 15 more minutes, to close this briefing with his plans on reworking some assumptions regarding electric generation in the west.

MR. VIDAVER: Thank you. Good morning. I work in our electricity analysis office, and I sort of run the crystal ball on the supply side.

The forecasts from our office that were used in this report are about six months old, and a few things have happened in the electricity sector in the last six months.

SPEAKER: Can't hear you.

MR. VIDAVER: Oh, do I have to stand this close?

SPEAKER: Don't hide your light under a barrel.

(Laughter.)

MR. VIDAVER: Let me regain my composure after that comment.

(Laughter.)

MR. VIDAVER: That's a visual I'd rather not have. I think I'm going to have the same problem. This is really -- I'm just going to shout. I don't like things that close to my mouth.

Let's see here, where are we. Okay. We've changed quite a number of assumptions about the amount of capacity that's going to be built in the western United States over the next ten years. Most notably, the amount of capacity that we think, the generation capacity that we think is going to be added between 2002 and 2005 has fallen substantially. I think we drop off about 8000 megawatts of capacity.

The high prices of 2000, 2001 engendered a lot of announcements about new combined cycles that were going to be added throughout the western

United States, both in California and the southwest, and in the northwest, and Mexico, as well.

So we've reduced the amount of capacity that's going to be added over the next several years. There is a graph two pages down which will show you the quantities involved. I'll discuss those in some detail.

The reductions in capacity are most substantial outside the California/Mexico region. The total amount of capacity that we think will be added in California and Mexico over the next decade is roughly unchanged. We just think it's going to be added later rather than sooner.

The total amount of generation capacity being added in the west has dropped by about 10,000 megawatts, and I'll discuss the reasons for that. And finally, we've incorporated the renewable portfolio standard, which mandates that 20 percent of the electricity in California be generated using renewable technologies by 2017. This will displace approximately 2000 to 3000 megawatts of baseload gas-fired capacity, and will require some additional gas-fired peaking capacity to back up the wind generation that's going to be used to meet the renewable portfolio standard.

So, the exact quantities, we would love your input. You can come back here on February 25th, we'll be holding a workshop to discuss the various assumptions that we're making for the integrated energy policy report and the assumptions that are quite a bit different from the ones that were used for this report.

This is probably preaching to the choir. You notice that when Mignon showed the future trend in gas consumption by generators, there was an initial dip in 2003 and 2004. We expect that EG gas demand will fall as new combined cycles displace older steam turbines that are currently used for baseload generation.

This is primarily a California phenomenon. As you know, gas-fired generation isn't as prevalent in the northwest or in the southwest where hydro and coal are used, respectively, as the dominant fuel sources.

There are limits in California to the extent that new combined cycles can displace existing less-efficient steam turbines. Those limits may be overcome with time, but the older steam turbines, primarily in the South Coast Air

Basin, in the San Diego area, and to some extent in the San Francisco Bay Area, Potrero for example, can't be replaced very quickly. Ultimately, I'm sure they will be, but that won't happen in the next two or three years.

To the extent that you add too much generation capacity you really don't have an additional effect on gas demand by generators. You simply spread that gas demand out over more capacity.

If I add 5000 megawatts of combined cycles and they displace existing units and are used to meet incremental demand, and then I add another 5000, that additional 5000 merely takes output away from the first 5000. So to the extent that we are over-building the electricity system, generation-wise, we are not really having a market effect on gas demand. And we'll return to that.

What it means is our lowering our assumptions about additional capacity that's going to be added really don't affect the total amount of gas the generators demand.

Eventually new capacity will just be used to meet incremental load growth, which simply means that the driver for gas demand on the part of generators in the long run is going to be the demand for electricity. That, and the technology improvements you have for gas-fired generation.

Gas is, as I'm sure all of you know, the marginal fuel source in the west about 90 percent of the hours of the year. As we continue to grow we're going to consume more gas. That will be offset somewhat by additional renewable technologies that may be used -- will be certainly used in California, and possibly in other states.

And finally, it seems absurd to say that the location of new gas-fired units affect gas demand. It doesn't really affect total gas demand, but it does affect how much gas is going to be demanded in California. And we'll return to that, as well.

Sorry I couldn't make this very simple. This is a graph that attempts to show how our capacity assumptions have changed over the past six months.

The blue bars represent our forecast from last August. The red bars represent our current forecast, our provisional current forecast.

The first pair of bars show the changes

in assumed additional capacity over 2002 to 2005 in each of these regions. The second pair of bars show the assumed changes in additional capacity across the two forecasts, not from 2005 or 2006 to '12, but from 2002 to 2012.

So, for example, if you look at the Pacific Northwest, in our forecast of August we assumed a certain amount of capacity would be built in the Pacific Northwest between 2002 and 2005. And that number has fallen in our current forecast by almost 3000 megawatts, 2789. The total amount of capacity added from 2002 to 2012 in the northwest has fallen by 2924 megawatts.

SPEAKER: So the 6 should be a 2, is that what you're telling us?

MR. VIDAVER: The 6 should be a 2, yes, exactly. So, hopefully that's clear. Let's discuss some of the implications of these changes.

Well, the capacity in the northwest has fallen because it's become apparent that the aluminum industry in the northwest is probably dead. Future prices in -- electricity prices in the northwest combined with increases in aluminum capacity in China probably mean that the aluminum industry is going to disappear.

The significance of this is that the aluminum industry is 15 percent of the electrical demand in the northwest. With it gone, about 3000 megawatts of generation capacity is no longer needed.

There are similar explanations of declines in other areas. In Canada, for example, it seems as though a very very large portion of increased demand in Alberta is going to be met by cogeneration. And therefore, the new capacity will not be produced output which will be injected into the high voltage grid, which means we don't care about it as a planning and forecasting agency.

In the southwest you see that we've reduced the number, the amount of new capacity to be added for 2002 to 2005, by 1200 megawatts; in the longer run it will fall by 3000 megawatts. These changes, while they seem minor, are actually pretty substantial.

Remember that from 2002 to 2005 there's a whole lot of stuff that's already there. It went online in 2002. It's coming online by the summer of 2003, and it's all but started up. So some of the declines are actually pretty substantial about what's going to come online in 2004 and 2005. The decline in the amount of capacity we've assumed in those two years is substantial.

The California number is a little misleading. The California number includes Baja California. And our assumptions about Baja California are that more capacity is going to appear in the next three years, and the next ten years. It's beginning to seem like Baja California, for whatever reason, is a place that people are going to want to locate power plants. And you can attach all sorts of nefarious motives to this.

But if we were to disaggregate California and Mexico, the decline in the short run in California would be more than 2480 megawatts; and the decline in the longer term would probably be on the order of 2000 or 3000.

So, that being said, we don't expect that changes in these numbers are going to affect the total amount of gas demanded by electrical generators over the next 11 years. We don't really expect the changes in the demand on the part of generators for natural gas in the next three or four years are going to be substantially different in our new forecast.

So the bottom line is despite all the changes in the assumptions we are now making about new electrical generation capacity because of what we've observed in the last six months, it's really not going to affect the numbers that are presented here. It will, in one respect, and that is because we have reduced so much capacity in the northwest and in California, southwest generators are going to run at much higher capacity factors.

Six months ago we looked at how much capacity was being added in Arizona, and thought, these guys are going to lose money. They're barely going to be able to generate profitably half the time. But our tentative results, changing the capacity additions, indicate that generation in Arizona is now going to be profitable more hours of the years.

So capacity factors on generators in Arizona, new combined cycles, are going to go from 48 or 49 percent up to about 70 percent. That simply means that Arizona generators are going to be providing power to the Pacific Northwest and California more than under the old scenario. And that means they're going to be demanding a lot more gas.

The reduction is going to occur in gas demand in the northwest and in California. So that's the tentative results that we've come up with.

I have about three or four minutes that I can take questions. I'm sorry, I have to leave. Yes, ma'am?

SPEAKER: Can you explain the Rocky Mountain numbers --

MR. VIDAVER: No. The way we put these -- the way we put the Rocky Mountains -- the Rocky Mountains aren't really important to us on the electricity side, because they're such a small share of load, of electricity demand.

And the way we gather information about the Rockies is to look at announcements, press releases, filings at the Public Service Commission of Colorado. And up until six months ago there was a proposal to put a chain of ten 500 megawatt power plants together in Colorado. We didn't really believe that, but there was a lot of activity, a lot of proposals in the Rockies, especially during 2000 and 2001.

Developers thought, I can build a plant in the Rockies, reasonably close to gas basins, and I could ship the power to California because they're going to pay me $300 for it. Well, the moment that $300 lost a zero, a lot of these projects were canceled, mysteriously disappeared.

MR. MAUL: Mr. Kelley.

MR. KELLEY: The scenario that has the southwest generators increasing capacity, look at the northwest and California, is there transmission capacity compounding that increase?

MR. VIDAVER: We don't see any transmission constraints running into California and going up path 26, path 15, and going north to the northwest. There may be transmission constraints on SWPL getting energy into San Diego. But we think --

MR. KELLEY: There aren't many infrastructure needs to accommodate that.

MR. VIDAVER: Other than San Diego, not really. The infrastructure needs are largest with the capacity additions in Mexico. Those are stranded. And getting power from Arizona into certain pockets in southern California. It's something we need to look at more carefully. But the models right now are saying there's no problem getting power from Arizona into the northwest.

Yes, sir.

SPEAKER: To the extent that some of this new capacity was going to lower capacity factors in the older plants, is there still enough new capacity coming on to make that happen? Or are we going to see some of the older plants running more because --

MR. VIDAVER: No, the system, even under our newer assumptions, the system is over-built to the point that capacity factors on older steam turbines in California are going to fall. And this, of course, begs the question are they going to stick around for ten years.

From a modeling perspective it's not really all that important because they run at about 9300 Btu, and their capacity factors drop down to let's say 10 to 25 percent. But one, they're fully depreciated, so perhaps with some assistance they can stick around. And secondly, they can effectively be replaced by LM6000s or other peakers that run at 9300 Btu, and leave you the same amount of gas consumption. Just a different type of plant that's doing it.

The older steam turbines end up meeting peak -- I wouldn't say peak needs, but 12-hour needs during the middle of the week, later in the scenario. And an LM6000 can probably do that more efficiently. So, even if these plants do disappear they'll be replaced by LM6000s or Frame 7s which effectively have the same effect on gas demand from a modeling perspective.

Thank you very much.

DR. GOPAL: Well, thanks, Dave. Now that we have got the first session on demand assumptions out the door, literally speaking, because this is going to be a pretty big driver. We have seen the national demand levels for natural gas, for example, in Annual Energy Outlook published by the EIA. The levels that they project, they keep going up and down from year to year because of the dynamic nature of how the market is functioning.

That's where I think there is a little bit of a criticality that we need to address to make sure that we can capture this well, and this is exactly where I need a lot of input from you, too.

A couple of announcements that I want to make. This demand assumption that we talked about, it's very dynamic, it's still in the process of evolution. There are changes being made, so we are now at the right point where we can actually take more input in making sure that we come up with some credible, reasonable demand projection for the future. So I do want to make sure that you are involved in that development.

The numbers that we are going to take from you will then go into the next round of analysis which we call the 2003 natural gas market outlook. That will feed the electricity and natural gas report that we will be publishing around the June/July timeframe. The results of that will then be fed into the integrated energy policy report that will be published by the Commission. The first draft will be out in July/ August timeframe. The schedule is being worked on; probably there will be some changes later on. But otherwise, we want to make sure we get that report out by November, as the mandated date is in November.

Stay tuned, come up to the CEC Website and you'll get all the details on the IEPR and other schedules that we will be developing over the timeframe.

Before we get going with the next session --

SPEAKER: Jairam, I wonder if I can just add one quick note to that? One of the pieces of analysis that we're working on in this demand part that we would like feedback on is the question of fuel switching in the entire country. The ability, given the evolving air quality regulations, of boilers and power plants and factories, what-have-you, around the United States, to continue to fuel switch; that is, switch from gas to oil and back. What the future would be like if basically everyone becomes like California and eliminates fuel switching.

So, to the extent you have any comments on that particular topic, we'd appreciate receiving those.

SPEAKER: Could you say a few words about what your thinking was with whatever went into the bottle this time around?

DR. GOPAL: I think that issue will be considered in the supply side discussion, because that's one of the modeling questions that we're dealing with. So we will cover that in the supply regs in the next session that's coming up.

Before we start with the next session I want to get some of you folks up on the table near the microphone so that we can listen to you very well, because we are being audio Webcast, so I want to make sure that every speaker sticks close to the microphones. I didn't get a chance to pull Dave in close to the microphone, but from now on I will make sure that I do get you closer here.

On the panel here I have -- my plan is to have this panel up there throughout the day. The members on the panel can drop in and out depending on, you know, the level of issues being discussed and their interest in each issue. This way, I think what we will do is get your input and thoughts right from the beginning.

Eric Eisenman from PG&E GDM; Kirk Morgan from Kern River Pipeline; Chris Price from EnCana; Mark Meldgin from PG&E Company; and Dale Nesbitt from Altos.

Is there anyone else who would like to be on the panel? This is not the last opportunity. If you want to join in later on to ask questions or provide input, you're most welcome.

(Pause.)

DR. GOPAL: And people who would like to ask questions, I would like you to speak loud. And if you cannot speak loud, come to the microphone up in the front and make sure you announce your name and affiliation so we can get it on the transcript. We need this transcript to make sure that we have a full record of the different questions and responses.

(Off-the-record discussion.)

DR. GOPAL: Okay, I do thank the panel for obliging to come sit up there, and provide answers to all our questions.

I'd like to now start off with the next session which is on natural gas supply. This will be led by Leon Brathwaite.

MR. BRATHWAITE: Good morning, everyone. Thank you for coming. Quite a turnout, I must say. I don't remember having a workshop in my 13 years at the Commission and seeing so many faces out there. It's nice, thank you.

Anyway, I will talk a little bit about the supply side issues, and I'll also briefly discuss the model that we use to do our projections.

The model is a very data intensive model, I must say, so what I'm about to present is a very simplistic view of what we do upstairs.

Anyway, by the way, my name is Leon Brathwaite, and I work in the gas unit.  I spend most of my day, if not all of it, with our model.

Anyway, we use a North American regional gas model, and we have been using it since 1989 to do our price and supply forecasts.  The model is a general equilibrium model.  But we make our assessments in three broad areas, that is the United States, Canada, and northern Mexico.  We do not have very much detail in Mexico, and this is something that is still evolving.  Hopefully in the near future we will have a little more detail in the Mexico area.

And so what do I mean by general equilibrium?  What the model does is that it simultaneously solves for price and supply; it looks for price and supply equilibrium in 18 North American supply regions and 20 demand regions.

Now, in the model demand is inflexible. And what do I mean by that is that demand is an input to the modeling.  It is not something it spits out.  We put in the demand and what we try to get out of the model is a price and supply forecast.

This forecast is done over a 45-year time period, but we primarily focus on the first ten years. When you get out 45 years, you really get out into some strange lines out here, so we stay away from that.

Anyway, in the supply regions we have different types of formations, conventional and unconventional formations. And what I mean by unconventional is that there are things like coalbed methane is considered unconventional; tight sands is considered unconventional, even though tight sands is not really unconventional, but it is considered in our model.

The supply resources are treated as exhaustible; that is Hotelling economics. There is quite a lot of discussion about Hotelling economics these days, especially in our unit. But it is something that we do have in the model.

However, several years ago, I think it was about five years ago, we added a reserve appreciation parameter which sort of minimized any depletion effects, and I don't want to get into too much detail, but what Hotelling economics does is that it calculates a scarcity rent. And there is appreciation parameter minimizes that effect.

In the model the supply and demand regions are connected by pipelines or pipeline corridors. On pipeline corridors, maybe, for example, like the El Paso and, El Paso North and Transwestern is combined as one pipeline in the model. Even though in actuality it's not, but that's how we treat it in the modeling.

And we have various parameters in there that we use, that we all input into the model to make this mix. We have technology parameters; we have reserve appreciation which I was just speaking about. And we have discount rates.

Okay, the model contains two categories of reserves. We have proven reserves, and right now we have about 236 tcf in the United States and Canada. We have potential reserves, which is about 972 tcf in the U.S. and Canada.

In addition, we have a category known as reserve growth, which comes from reserve appreciation. What happens is that as a field expands we have new estimates of the amount of reserves that's present. Also new technology that improves recovery and production. And also we have in-field drilling which taps into new pockets of reserve that we were not aware of previously.

So what the reserve appreciation parameter does is try to account for all of those things. So that is also a reserve category, and that only works on the proven category.

Okay, proven reserves require only O&M costs for its production, whereas potential reserves require both capital and O&M costs. And the proven reserves and their associated costs form the basis of what is known as raw supply curves. And the supply curves are very important for the running of the model.

Now after we do all that, you know, we put all these things into the model, both the demand side and the supply side, and all the intervening parameters, we end up with something like this. I mean the model doesn't spit this out, but this is what is the information that comes out of the model.

So in this graph here, in this schematic here we have the oval, the oval shapes represents our -- everybody hear me? Can everybody hear me? Okay, good.

The oval shape represents our supply

regions, you know, like we have San Juan, Permian, Anadarko. Those are all our supply regions. The black circles represent all the minor regions.

Now, in California, even though it's represented on this particular schematic, it's represented as only one region, actually in California we have a lot more detail in the model. I think we have four regions in the model. So, but here, for simplistic purposes, we just represent it as one.

And the lines, the lines between the demand and the supply regions, those are all pipelines or pipeline corridors.

Now, again, this is information that spits out the supply, that's spit out from the model. And as you see from the schematic, the Gulf Coast, according to our projections, is going to hold around 10 Tcf or so short of our forecast horizon.

We have Rocky Mountains, which is going to show substantial growth from about 2 Tcf to about 4 Tcf before the end of our horizon. And we expect a lot of production in Canada, because we can see it going from a little less than 3 in 1997 all the way up to over 5 Tcf by the end of our forecast horizon.

Now, these are our future plans and discussion topics. And here we are really seeking input from you guys. Reserve appreciation, what should we do about that? There is a lot of discussion about that. Is it, are the numbers we're using high? Are they low? You know, it's just a lot of issues involved with that. We really seek some input there.

The supply cost curves; we need to take a second look at them to see if the associated costs are reasonable. Technology factors. How fast will technology be improving. These are things we want to talk about.

Bob started the issue about the end of fuel switching. It's something that we definitely need to look into on our next cycle. And the other issue that we are also looking at is what should we do about modeling gas on the North Slope? And the LNG, also, which is quite prominent these days. Bill will talk a little more about LNG.

So these are the issues where we are really seeking input from all you participants. And that concludes my presentation. I will take any questions. Don't make them too difficult otherwise Jairam will have to answer them.

(Laughter.)

MR. BRATHWAITE: Yes.

PROFESSOR WILLIAMS: Have you used this model to backcast, say put in 2002 numbers but demand for the previous ten years, how well you accord with the supply that occurred in 1992? The model shouldn't care whether it's forecasting or backcasting.

MR. BRATHWAITE: No, we have never done that, quite frankly. Dave probably could --

MR. NESBITT: Dave did a lot of that. Have you read "Random Walk Down Wall Street" by Burton Malcheal? Do you want to backcast after that?

PROFESSOR WILLIAMS: Yes, I want to backcast the model --

MR. NESBITT: Do you want to do statistical backcasting? Most people who do backcasting, in my humble opinion, do it dishonestly. You can fit an electrocardiogram with your model, most people do, and then they demonstrate that it's reliable.

The real interesting thing about

backcasting, we're seeing that today, is if you're going to backcast you've got to understand how price expectations are formed and were formed five years ago. Do you gather data on price expectations five years ago? No. Do you gather data on price expectations now? No.

We can talk about that; that's not right.

MR. BRATHWAITE: Well, wait, wait, wait, no, no, no, Dale, I'm not sure I agree with what you just said there. You say, it is a perfect foresight model.

MR. NESBITT: It says it has no -- it has price expectations in it. Just like the real world has price expectations in it.

MR. BRATHWAITE: No, but, excuse me. Are you -- did you want to --

PROFESSOR WILLIAMS: I still think any model you can, I think you can do backcasting with, and it gives you some confidence in your forecast. So why not do it, that's all I was asking --

MR. BRATHWAITE: Oh.

PROFESSOR WILLIAMS: -- if you've done it.

MR. BRATHWAITE: No, we have not. We have not. Maybe it's something we should consider doing.

MR. NESBITT: If you're interested I'll show you some of that stuff.

MR. BRATHWAITE: I'm sorry, somebody else had another question.

SPEAKER: Well, I was curious, there was nothing up there about somehow price expectations as inputs to the model.

MR. BRATHWAITE: Well, the only -- no, no, we don't, we don't have prices on other inputs in the model, no. We have some cost input data, but not prices.

MR. MAUL: Leon, repeat the question.

MR. BRATHWAITE: Which question?

MR. MAUL: Repeat the question for the microphone. The last one.

MR. BRATHWAITE: Oh, I'm sorry. Your question was you were wondering why there is no price expectations.

MR. NESBITT: It's a dynamic rational expectations model. It's a price expectational model. It's dynamic rational expectations. It means that price expectations are rationalized with the decisions that profit-seeking producers engage. So price expectation is at the heart of what these guys do.

No. Wrong. It does not come out of your supply curves. What does dynamic corrected rational expectations mean, do you know? It means that as you sit and make decisions today you have to form some expectation about where price is going in the future, and your decisions today depend on price expectations. Everybody knows that.

But forward price depends on decisions you make today, they're coupled.

SPEAKER: The question is how does the model do that.

MR. NESBITT: How much time do you have?

SPEAKER: It seems like it's an important feature, so --

MR. BRATHWAITE: Well, give us a one-minute version, then.

MR. NESBITT: How does the model do it? If you think about -- the model doesn't, and I hate to use these anthropomorphisms that the model -- I'm sorry, that these models think, because they don't think. The people that build them think.

If you posit that producers and consumers in California, I know it's hard to believe, anticipate prices as best they can, and they make investment, operation, and retirement decisions in the face of the prices that they estimate, that's what actually Mobil does, it's what BP does, it's what PG&E does, everybody tries to do that, right.

If you put that agent-based approach into Leon's and Jairam's model, that people pursue profits as best they can, then you'd like to have two properties. You'd like to have the people not doing systematically stupid things, making decisions based on systematically knowingly bad price forecasts.

The theory, in reality, tells people, don't do that. If they make decisions based on price forecasts, they make them at random. This model doesn't do that. There's no randomness in the model.

It says that the capacity addition decisions are consistent with the prices. And the prices are consistent with the capacity addition decisions. There's a rational expectations dynamic equilibrium set up. Nobody does anything systematically stupid in the real world or in the model. They only do things that are stupid at random.

And when they do something that's stupid at random, what's the degree of freedom? The price, the price changes. Takes care of the weak and it takes care of the strong.

Does that create a lot more confusion than you started with? Probably.

SPEAKER: As I understand these models, what you put in is, in the various basins, what it would cost to produce the next increment (inaudible) and on a cost basis. Then the model balances all that stuff with pipeline capacity and demand and like stuff. It comes out to a price where supply and demand are balanced.

Now, that's a cost-based thing, not a market-price base thing.

MR. NESBITT: That's wrong. It's going to take a lot longer to -- that's not right. That's not right in the real world, it's not right in the model. This model.

These other models you're referring to, I don't know what you're referring to.

MR. MELDGIN: If I can throw in two cents here, I'm Mark Meldgin with Pacific Gas and Electric. I've actually done backcasts with MarketBuilder for the electric model, and you can see the results in the testimony in the Gas Report II.

The key features --

MR. BRATHWAITE: Just for clarification, MarketBuilder is the Windows version of the NARG model, the North American Regional Gas model, okay.

MR. MELDGIN: Thank you, Leon.

MR. BRATHWAITE: Sure.

MR. MELDGIN: NARG and MarketBuilder have in them a switch in which you can tell the model, yes, go ahead and add new pipeline if it appears to be cost effective to do so. Or, no, don't do any of that.

If you turn that switch off then, well, that's what I did for my backcast. And I put in recorded gas prices at different places and then let the model figure out what the electric, the power plant gas demand was going to be, starting in January '98.

So it is possible to do that sort of

backcast. And it came up pretty darn well. But the kind of thing you're talking about --

SPEAKER: I wasn't worried about backcasting --

MR. MELDGIN: Oh, that was your question back there about backcasting. I apologize.

MR. BRATHWAITE: No, yes, it was Jeffrey Williams who asked that question, yes.

Anything else? Carl, I'm sorry, Carl.

MR. FUNKE: I have a couple of questions. First of all, is you started in what, '97 as a base year? You go every five years --

MR. BRATHWAITE: The base year, yeah, it's '97, yes, yes. I'm sorry.

MR. FUNKE: How did 2002 end up compared to the actual 2002? And is it wildly different? And is that okay, because we're really looking at long-term trends that kind of take out volatility?

MR. BRATHWAITE: Do you want to take that?

MR. PETERSON: I'm Todd Peterson with the Energy Commission. From a price-wise aspect, taking a look at what, say the Gulf Coast price came out of the NARG model, compared to lower 48 wellhead price, on a simple average for the recorded data by EIA, it comes out relatively close. We were looking at about $2.83 per Mcf out of the model.

EIA recorded data through about August of 2002 is relatively close. It might be a little bit higher, close to about, I believe it's about $2.90. These are all basically in 2000 dollars, so it's adjusted for inflation.

MR. BRATHWAITE: Do you still have another question?

Yes, sir.

SPEAKER: I notice your curve fairly flat both for industrial demand and cogeneration. And I recognize that where you have very large gas users, also large electric users, that market may be saturated for cogeneration. But the technology seems to be allowing lower level industrial users to try that. And I'm wondering why you have such a flat curve for cogen.

MR. BRATHWAITE: Yeah, I was just looking around. Is David here?

DR. GOPAL: No, he's not here. You'll get that answer later.

MR. BRATHWAITE: We will deal with your

question, sir. Another question.

MR. FUNKE: Since investment dollars are kind of, you know, limited, and big oil and gas companies now can put it internationally, do you have to have an international scope to this, Dale, or --

MR. NESBITT: Yes. I spent Wednesday with big international oil companies on the NPC project. Many of you will be hearing about that. And believe me, their capital budget, and it is international and it is risk-adjusted, absolutely. Good insight.

MR. FUNKE: Another question. I guess an Interior study recently said that there's only 11 percent of the Rocky Mountain reserves that are actually off limits to drilling. Is that included in these -- is a portion that you have, your supply, just completely eliminated because you don't think it'll go through? What are the assumptions of that and what do you think about that?

MR. BRATHWAITE: Well, Carl, that is something that actually we are discussing right now, and it will be in our next cycle. We are looking into that. It was not something that we truly addressed in this particular cycle, but we certainly will be addressing it in the next.

Bill.

MR. WOOD: I have one comment about that. The United States Geological Survey just put out their new Rocky Mountain assessment. I have the, what do you call it, the fact sheets for that.

They've revised the Rocky Mountain estimates down slightly in terms of aggregate volumes producible. But they've gotten a bit more bear-ish on the continuous formations out there, the unconventional gas, in the sense that their cost estimates implicitly are a lot higher.

So, it's not just an issue with federal land access. It's also an issue of intrinsic cost of resource, and an issue of the size and depth of distribution of what's out there.

And a lot of people are getting, if I can see the trend, a little bit more bear-ish on the fundamental geology out there.

Last point on land access. It's just not -- it's not whether or not you have land access, it's what you got to pay for it and how much liability that you're going to bear if you should, god help us, kill a piece of wildlife or something.

So it's not just an issue of land access. It's an issue of the liability that you take on when you go drill there. That's why internationalization really matters. Where are you going to take on your liability, in Wyoming or the Ganges River Delta?

MR. BRATHWAITE: Yes, Carl.

MR. FUNKE: One other question.

MR. BRATHWAITE: Your last one? No.

MR. FUNKE: No.

(Laughter.)

DR. GOPAL: We have plenty of time for questions.

MR. BRATHWAITE: Yeah, it's okay.

MR. FUNKE: No, this, I mean, these are all just general questions. But your LNG assumption for Baja specifically, okay, there's a -- you got a bunch of people that are interested in putting something in there, it looks like it's cost-effective. How does that go in as a supply, since it's not something you have any history on? And at what point does that kick in, and what level?

MR. BRATHWAITE: Well, in this -- Bill, I'll ask you to answer some of question, okay. But in this run we didn't really look at LNG in Baja. But we do have a scenario that we did that considered LNG and being constructed in the Baja area. And we have seen quite good flows in the model from LNG in Baja.

MR. FUNKE: What did you just say?

MR. BRATHWAITE: Quite good flows.

MR. FUNKE: Okay. But is it a significant difference in price, or pipeline infrastructure or --

MR. BRATHWAITE: No. No. Not significant, I wouldn't call it significant. But I'll let Bill answer some of this question. Bill, go ahead.

MR. NESBITT: I don't want to monopolize the time, but if you look at some of these LNG projects down there, people are talking about 500 to 600 Bcf a day times four. And that basically more than saturates the Baja demand and pushes into SDG&E and into SoCalGas service territory by displacing by direct physical flow.

The issue there is once you build yourself an LNG facility on the Northwest Shelf or somewhere like that and you put yourself nine boats in the water, you're going to sell it and you're going to take whatever basis comparison you get.

The way a lot of people are thinking about that is do I want to put up the $20 billion it takes to make one of these things and take whatever price I get in Baja California, and de facto the whole southern California tranche down there.

Okay, so the projects are big and they do have significant depressive effects, and they do back pipes like North Baja up, absolutely.

MR. BRATHWAITE: Okay, Bill.

MR. WOOD: I wanted to go back to a couple of questions back that Carl indicated here. First it has to do with, first with the Rocky Mountains, whether we are including 11 percent or not. That's one of the things that we're looking at. And as Dale indicated, there are costs associated with restrictions on those where there is access. But, as I say, there is some restrictions. Some of them are minor and some of them are a little more heavy.

We're looking for input anybody has on

that sort of information. Currently we have all the Rocky Mountain gas reserves available and working in the model. But when we do our next round we want to -- we're looking for information with regards to should we include that 11 percent, or is that included, would that be included in being able to forecast potential resources that are available in the Rockies.

Or should we actually take our estimates that we have for the Rockies and cut them back by 11 percent.

In addition, there's, if I remember right there's about 35 or 40 percent of the resources in the Rockies which are on some level of restriction. Well, as I said, that restriction has some costs associated with it, probably, because you have drilling times that are restricted, and maybe you have some restrictions on how you can have access to that particular property.

No analysis that I'm aware of at this point has gone through to say what kind of cost implications that will have. We need information on that. If you've got it we'd love to see it, so that we can include that into some of the analysis we're doing.

So, just asking the question and say yeah, we're going to do it, fine. But we need your help in doing that. So if you've got input in that area, fine.

With regards to the LNG potential on the west coast, I'm going to be talking about nine or 10 or 11 facilities that have been proposed. But we did a real quick and dirty analysis this summer where we put a 1 Bcf facility in Mexico, one in southern California, one in northern California.

And then we ran each of those individually and then we ran them all together. So we had four scenarios. Like I say, it was a very very quick and dirty analysis. We just assumed the landed price of LNG at $3, I think it was, with a 50 cent cost to gassify and get it ready to tailgate. And then just let the model run from there.

Basically what happened in the all LNG case, the winner was southern California. It ran at full capacity. And the second winner, if you would, would have been northern California. And the third was the one in Mexico.

Basically what we are looking at was the one in southern California was right in the middle of a huge demand center, and it was backing out southwest gas, which is our most expensive gas coming into California.

The second, or the one in northern California came in because it's again in a very large demand center. It's centered right there where there's a large gas demand. But it's competing against cheaper Canadian gas, so it didn't fare so well.

And then the one in Mexico is not in a large demand center, and there are costs associated with moving the gas out of Mexico into other demand centers such as northern California or eastern California. So therefore, it did not fare as well.

But nevertheless, all of them looked like they were going to be economic the way they were operating.

Now, in each case, for each of the demand, each of the supply areas, the citygate price dropped from our base case when there was no LNG. So therefore, the impact of the LNG was to reduce the cost of gas delivered to California.

And in so doing, of course, it reduced

the quantity of gas coming in from the different regions into California, depending upon the region and whatever.

But we never looked into that specifically because, like I said, this is a very rough -- was a really rough evaluation, just a quick and dirty one. Jim Fore is working with us now and he's been working for the last two months gathering information for us so that we can do a much more in-depth analysis on the Pacific Rim.

He's gathering information on each supply source, each demand location in the Pacific Rim that is taking LNG, and coming up with some information that we can then put in the model with regards to each of those supply sources, the cost of moving gas from those supply sources to California, and to each of the other demand regions inside the Pacific Rim that could have access to that LNG.

And also then costs associated with each of the supply regions to try to determine then what is going to be the wellhead price, or the price to get the gas into an LNG facility. And then the costs associated with liquefying it, and then the transportation costs.

So, all of that is a much more detailed analysis that we're doing now, trying to pull together. And, again, if you have information in that area, sometimes not all of this is readily available in the public sector. So if you have that kind of stuff, information available, we're looking for that to help substantiate the work that we're doing here.

But that kind of information is going to go into our analysis. The question arises now, is should we be doing this on a base case basis, or should this be used as a scenario, as a "what-if" happens. And if it is, should we do like we did before, do we do a four-case scenario where we're looking at one, two and three facilities, and then all of them together?

Then how do we run that against McKenzie Delta and North Slope? Do we include those in our base case? Are those again sensitivities? Do we do basically what we call an all pipes case, where we put everything in and let it run and see what happens, who makes it and who doesn't.

We're looking for information. We're sorting through this, but any inputs that you have we'd love to hear what you have to say now or in any written comments that you have in the future with regards to this.

Anyway, talked too long.

MR. BRATHWAITE: Before you take off, thank you. I think you had a question.

SPEAKER: Bill, you said you have one facility in Baja, LNG for 1 Bcf, one in south California and one in north California. These are in the present model?

MR. WOOD: No, that is not -- no

I'm sorry, the work that we have done up to this point and published has LNG only in the four existing facilities on the east coast.

MR. WOOD: There's no LNG in California. This, what I did here was a real quick and dirty study that we put together just to see what-if. What was going on to get a kind of a broadbrush look to see what might happen.

Anyway, yes, Bert.

SPEAKER: Well, your thing about wildcards, you've got to consider the fact that Mexico may recover from their present Marxist national chauvinism and start actually developing some of their potential.

Petroleum geologists, for instance, like the outside look. They've never been allowed to do any real exploration, but they like the outside look of southern Baja, and in general. There's no reason to believe that Mexico isn't going to have a lot of fossil fuel potential if it's actually explored by people who know how.

So, I agree that that's not today, but I certainly think if you're going out as far as 2012, it's something you should at least have in the back of your mind.

MR. BRATHWAITE: Well, as I said in my presentation, you know, we do not have much detail about Mexico right now, but it is something that we will be, I guess is evolving that we will kind of consider as we do our next rounds and our future rounds of forecasting.

Yes, Dave.

MR. MAUL: Leon, I hate to add more complexity to the situation, but obviously we're discussing the LNG right now. As a separate activity we are looking at LNG from a variety of perspectives.

The State of California does not currently have a position on LNG development in California or in Baja. But we are examining the issue. Obviously it has a potential very positive impact on the gas perspective. We're examining all the details of that.

We need your input today to help us model that potential impact to see how large it is, and how positive that is.

On the other hand, if we were to issue a position statement on LNG, it would cover not only gas and energy issues, but also would need to address environmental issues, public health and safety issues, permitting issues and the public's concerns, and we have to have a comprehensive statement that looks at all those issues at once, and not just look at one aspect of it.

So, we are modeling it just to see what the technical implications are, and the forecasting implications. But we will not make a position statement to say we like or don't like LNG until we have something to say in all those areas.

And we are looking not only at the California situation, we're also looking at the Baja situation, in coordination with Mexican officials, including the President of CRE.

MR. BRATHWAITE: Thank you, Dave. Yes.

SPEAKER: Coming out with that California policy.

SPEAKER: We've initiated discussions with all the permitting agencies here in California and, as you can well imagine, that will take some time to work through the many agencies that might have a potential role in LNG permitting. So I'm not giving a time. It's beyond the ten years --

(Laughter.)

MR. BRATHWAITE: Well, thank you for that, Carl, I appreciate that very much. Yes, Carl, go ahead.

MR. FUNKE: This is not a pipeline question, but do you have all of the pipelines in the model for the ten years now, when they're, some of these projects you've identified, are some of them coming on or are you adding pipe in the interstate pipe from the southwest, let's say, to California as part of output of the model for ten years? Yes or no.

MR. BRATHWAITE: Well --

MR. FUNKE: No, do you have it in the model? It's just a question.

MR. BRATHWAITE: Yes, yes, yes, but

there is, in the model, there is a permit that allows the, whenever it is economic to do so the model will build capacity. Okay? So we have the flexibility to either put one of our pipes that we see coming on, say, in 2005 or in 2007, we have the ability to put it into the model as we see fit.

Also, within the model internally, the model can build capacity as it sees fit. So, like, if we see like there is, like, for instance, say you have some cross-over need expansion. The model can do that without us telling us to do so externally.

MR. FUNKE: Okay. My supply question is, you said that you expect U.S. gas production to peak at the end of this ten-year period. Who's going to be building pipe for something that's not going to have a supply for it, in the ten years, within the ten years.

MR. BRATHWAITE: That's a good question. Jairam, do you want to take a shot at that?

DR. GOPAL: Well, here we are talking about the long-term impacts of, you know, what's going to happen with prices of land, just building up to your question.

(Laughter.)

DR. GOPAL: See, basically I think we have, we presented a variety of gas resources throughout the U.S., and there is this anticipation that, you know, because this plant will be accessing this gas, although we said that the gas is peaking it's not that we're going to be running out of gas, first of all. What we will see is the gas is going to peak, but it's going to stay there at that level for a significant amount of time, otherwise the model would start telling us that, hey, listen, you are running out of gas.

The second thing, any computer model is, you know, it'll give back what you put into it. So if you check the model, and then if you tell it that, hey, listen, I got this alternative fuel which can compete at two bucks, and your resource costs, of course, drive the gas to four bucks, obviously the model will tell you hey, listen, you told me you got alternative fuels at two bucks. That's what you're going to use.

So that's one of the reasons what happens is if we put the oil price, for example, at $3 a bottle constant throughout the timeframe, there will be a point where it says that it's going to be a lot more economical to burn oil rather than gas. And that's exactly where we get into this environmental situation. You know, are we going to let this happen, will it happen, or will there be some resolution.

I think those are some of the issues that we are trying to address, and that's one of the reasons why we do sensitivities, to see, okay, in our base case we don't have a constraint on people to choose between oil and gas, and therefore there's a potential to use something else. So those are the different parameters that we play with.

So, when we say that the gas was peaking, for example, in the paper that we have issued, what happens is beyond that timeframe, gas prices seem to rise high enough that alternative fuels will start penetrating.

Now, the second aspect that we have in this model is what's called the backstop price, which says that there is at some point a significant amount of gas that's going to come in. So that's the one which will replace any other conventional gas resources you have examples, or what. Coalbed methane is one of the unconventional ones that we already have, but there are gas hydrates and the in situ coal gasification and other technologies that can come in if prices rise to a certain extent.

So, so that's what we mean. It's not that we're going to be running out of gas and the gas will no longer be useful, or used in the marketplace.

Any other comments? Dale?

MR. NESBITT: No more.

DR. GOPAL: Eric? Oh, hold on.

MR. EISENMAN: I wanted to comment on the questions with LNG in Baja. Those are questions nine and ten of the questions you set down.

DR. GOPAL: Can you hold on just one second? I want to make sure that Carl has his question answered on this one.

SPEAKER: Well, it seems that even though it, you said it peaked, I didn't mean that gas wouldn't retain the flow. Just the prices keep going (inaudible) tracking it, what, faster, I don't know what "peaking" means. Do your rates reserve depreciation factor got cut in half, now we can basically add, you know, supply to the technology.

DR. GOPAL: Yeah. Given the conditions that we are inputting to that particular reference case that we did for 2002, there was a significant shift to alternative fuels. For example, out in the future, 2017 and beyond. So it's a little more than ten years.

So there was a significant shift to alternative fuels. That's one of our inputs, so that's one of the things that we are investigating right now.

Eric.

MR. EISENMAN: Okay. I'm wearing a North Baja Pipeline hat for the next minute or two. We've passed out, or it was out on the front table, answers to questions nine and ten. North Baja is aware of six LNG proposals in Northern Baja, ranging in size from 750 a day to about 1400. North Baja is going to have an open season starting next month, a non-binding open season. So it's a kind of a start to gage interest.

North Baja has gone in the commercial operation and is flowing east to west now, serving generation in Northern Baja. If an LNG plant gets built, then there's not going to be six built.

There's probably, if you asked me to guess today, there are probably not even going to be two built in this kind of planning horizon. If one does get built, though, North Baja could start becoming west to east, with pretty modest capital costs, and get gas back to Ehrenberg, where it could either go into the SoCalGas line at Ehrenberg, or back, back into the Southwest.

So I, you know, it's our, our best guess is that there will be some LNG built in North Baja in the next few years.

MR. BRATHWAITE: Okay, great.

DR. GOPAL: And one follow-up --

MR. BRATHWAITE: Oh, you want to follow up?

DR. GOPAL: I want to follow up with the response you gave me. Yeah, what we did in the model for that sensitivity analysis was to turn North Baja to flow west to east instead of east to west. And you said there will be some feed. Do you want to throw out a number?

MR. EISENMAN: I'm sorry, some what?

DR. GOPAL: What's the transport cost on that west to east flows, when you do turn it around?

MR. EISENMAN: I don't know if we've gotten that far. Let me inquire about that.

DR. GOPAL: Okay. Yeah, because I think that would certainly --

MR. EISENMAN: That's a reasonable question, and I --

DR. GOPAL: And that's a critical one to --

MR. EISENMAN: It's a critical question.

DR. GOPAL: Yeah. Tell us whether it's going to be economically priced at the -- yeah.

MR. EISENMAN: Okay.

MR. BRATHWAITE: Questions, anybody else? Yes, sir.

DR. GOPAL: Mark Meldgin.

MR. BRATHWAITE: Mark.

SPEAKER: One comment I think that Carl may not have --

MR. NESBITT: One comment that Carl made is a good one. Who's going to build the pipe? It's guys who put pipe in places where the basis differential across the pipe is bigger than big enough to pay for it. You are seeing in the eastern U.S., I saw one a couple of years ago, hundred day pipe, and they built this pipeline just for peak load. I hadn't that before. And when you run it through the model you see the basis differential big enough to pay for the whole pipe for a hundred days.

So one of the things that started to happen as the country changes structurally where it's getting their gas is there's smaller pieces of assets that have very high value for a hundred days, but no value for the balance of the year, but basically eating, eating everyday pipes.

So you build them when the basis differential tells you to build, like Baja into San Diego Gas and Electric. Crash the price in Baja with a 700 a day LNG plant, there's going to be a big basis differential on that pipe, so I'm going to build it.

DR. GOPAL: Thank you, Dale. Mark, please, yes. Thank you, Dale.

MR. MELDGIN: I had a question, or, pardon me, a comment, actually, about NARG. You mentioned fuel switching. Something I haven't heard discussed on the gas side is demand destruction. The analogy is what Dave Vidaver mentioned earlier, electricity prices in the northwest have gotten so high because of the aluminum smelter, electricity demand is done.

I've seen various consultants say that in the lower 48 there's a pretty significant use of natural gas as feedstock for fertilizer and a few other things, and that when gas gets above some price, maybe four, four and a half bucks, that demand goes away. We start importing all the fertilizer from overseas.

So maybe that sort of thing ought to be put in the model.

MR. BRATHWAITE: Sure. That's certainly something we'll keep in mind.

Anything else? Questions, questions? Comments?

DR. GOPAL: Yeah, I had a question.

MR. BRATHWAITE: Jairam got a question. I'm sure he'll answer it himself, too.

DR. GOPAL: Okay. This is a question with regard to LNG, again. Should we treat LNG as a baseload supplier, or should we treat it as a peaker plant? What is the best use of LNG for California, and how does it impact the market and the economics? I mean, this is something that, if not now, I would like you to address it in some of your responses.

And gas used in feedstock, yes, that's a very good question, and we do understand that there could be a, I mean, is that demand shift going to be significant. We tried to do that with sensitivities. That's the only way that we can help really think of, and they're trying to grab what's going to happen in the marketplace. So we do look for sensitivities, and in that, of course, look at the U.S.-wide model. Just changing a number in California is not going to change the lower 48 average price.

For example, you're not going to really, the tail is not going to wag the dog. So we try to get some information and intelligence of how it's going to be a U.S.-wide change, and try to balance those in sensitivities. So if there are any suggestions or inputs, or questions that you have, I would like to see it so we can try and design the appropriate number and type of sensitivities to be addressed in the next cycle.

SPEAKER: The model does have the ability to handle price elasticity, doesn't it? You just put in stiff market, but include maintenance -- that might be one way to handle it.

DR. GOPAL: The model does -- Dale is

also nodding his head -- we have used the elastic version of the NARG model. We used to do that quite a few years ago. We really haven't focused too much on it in the last few years, because we have several other models, and the Commission also asked for the EIA or GRI, which we used as a source of input for demand numbers. I do anticipate that they have gone through the different parameters, they have gone through the competitiveness of gas and other alternative fuels. And also, about efficiency use and things of that, and come up with a projection.

So I'm trying not to re-do that same kind of analysis on top of it, so. But the only other time we treat it as an inelastic demand, where we know that that's the amount of gas that's going to be demanded in the market, and therefore that leads us to focus on the price and supply.

But I will certainly continue to focus on the elastic side of it.

MR. BRATHWAITE: Anymore questions or comments?

Hearing none, I will thank you for listening to what I have to say. I appreciate your coming.

DR. GOPAL: Well, the time now is 11:00. We still have time for, I think, to take the price issue up. So I want to start with Todd Peterson, leading the discussion on the prices.

MR. PETERSON: Good morning. I'm Todd Peterson with the Natural Gas Unit. I'll be going over our natural gas price projections that are in the staff report.

Briefly, I'll go over the methodology. As Leon has already went through, we've stepped through most of the NARG, which is the, getting into the wellhead price forecast, and into California border prices. From there, I'll show off a little bit of the price projections and discuss how we come up with sector-specific prices, both through the WECC for electric generation, and also for, in California, at the utility level, for customer-specific.

From there, we'll be discussing what we're thinking about doing, and looking for input for our next forecast and, and looking at it from a price perspective. And last, close this out with some of the discussion topics as we've already done this morning.

Our price projections are based upon

long-run or long-term economics, using annual average prices, and our forecasts to get into the end-use price projections uses three sequential analyses.

First, as we've discussed, we have the North American Regional Gas model. Again, it's a general equilibrium model for the North American continent. We also try to bound our prices by using innovative price and supply outlooks -- this is using different assumptions, which is in Appendix C of our report -- to understand how natural gas market conditions may change and influence wellhead prices and supply availability.

From here we take this information and move into end-use price projections. Here, what we're trying to do is determine the prices by matching supply and demand by each customer class, especially here in California and the WECC, and then we need to get into the utility-specific regions and we need to allocate some of their fixed costs. And these are things like interstate transport, inter -- oh, I'm sorry, intrastate transportation costs, utility margins, et cetera.

So starting from a big picture look, we're looking at North American wellhead prices.

And as Leon has already showed you, some of the basins that are producing well, we see the reason is, mainly, is some of the pricing. Here in green I'm showing off some of the economical prices, such as in Canada, we have Alberta. Here in the lower 48 we're seeing San Juan and Rocky Mountains.

Likewise, the more expensive places we're seeing, compared to the weighted average lower 48 price, is the Gulf Coast and California, and we're at -- something that's real interesting is for gas coming into California, we're seeing that Rocky Mountains and the Alberta, British Columbia supplies are looking attractive for the, throughout the forecast horizon. And the major reason for this is the relative maturity of these basins, and that is the Rocky Mountains are relatively immature compared to the Gulf Coast and California Basins.

So now that we have the wellhead prices, what we do is, using North American Regional Gas model, is bring in the transportation costs. And -- thank you. And here I'm showing off just a few of the prices that we were looking at in the WECC region, mainly just to illustrate how economical some of these prices may be.

For example, you take a look at the, any gas coming off of PG&E, GTN, Stanfield, up in Oregon/Washington area, you're seeing very economical pricing, mainly because of the commodity cost coming out of Alberta. And contrast that, if you're in California in the utility area, you're going to be looking at higher prices because you're not only paying for commodity and interstate transportation costs, but also transmission and distribution costs, where applicable.

Of interest here is what you're seeing back up in the Rocky Mountain production region. At the beginning of Kern River pipe, you're seeing some good pricing in that area, along with the El Paso North System being able to take gas off the San Juan production area. And so we're seeing good pricing there.

And what this is showing is kind of the relative pricing or competitive advantage some folks may be seeing, if you were going to place an electric generation plant in these areas. Of course, there's other things to consider, such as environmental issues, water, air, et cetera.

SPEAKER: What was the reason for kinking in the Kearn River price forcast? It wasn't obvious to me.

MR. PETERSON: Sure. What we're seeing here is -- The question is why do we see in the kink in the Kern River to California pricing. One of the major reasons is the capital cost is coming off in the later years, distributed over, over more production coming online.

Next we come into looking at California prices, utility-wide. I'm using here just a quick and dirty system-wide prices on an annual average basis. System-wide, meaning looking at it from residential consumers all the way down to industrial cogen and electric generation pricing.

What we see here is in the early nineties, we see the gas bubble helping keeping prices lower relative where they have been the last few years. As that's been worked off, we came into the 2000-2001 gas crisis, where we're seeing much higher pricing, approached $10, $11 figure. And then, recently we're seeing prices coming back down and we're forecasting prices to be around $4 to $6 range over the next ten years.

SPEAKER: This is a graph, because a lot

of people paused. But basically, you're saying that the spikes that happened in 2000 and 2001 aren't going to happen again in the next digit.

MR. PETERSON: What we're showing --

SPEAKER: That's the way people are going to react to this.

MR. PETERSON: What we're showing here, again, these are really based on long-term or long-run economics. And they are annual averages. We're not saying that you're not going to find increases in prices beyond this range, or decreases beyond this, but really, as you average them out this is what you're seeing. When we talked with Carl Funke's (ph.) question about how well our pricing is in 2002, looking back at 2002 we've seen wellhead prices down towards $2, and recently they may be moving towards $3.50, $3.75, maybe even higher. The data aren't out yet.

So when you put those into an average basis, you're moving more towards some of these prices here, $4 to $6 we see, including transportation costs.

Carl.

MR. FUNKE: Todd, the model still starts in '97, goes every five years; right? So really, you've only got three data points you're looking at, and you've just got to draw a ruler line between them. So you're not going to show volatility, price spikes, or anything like that.

MR. PETERSON: Right. We're not going to be -- the question is that our, our North American Regional Gas model, it's a five-year increment model, and consequently you're not going to see volatility in prices. And I agree that that's what is being seen here. As we discussed on the demand section earlier this morning, what we're looking at is annual average demand conditions, meaning we're looking at average hydro conditions, average temperature conditions. We're not seeing any variability, we're not looking at the seasonality of demand.

Yes.

MR. FUNKE: Just to clarify that, and this is going back to an earlier question. You are not forecasting that the big spike in 2000 and 2001, will not recur. You're just not making any assertion about that at all.

MR. PETERSON: Right. The question is, if we're, if the Energy Commission is making an assertion that the price spike of 2000 and 2001 will not occur.

Again, no, we're not necessarily saying that. What we're saying is based on average conditions, average demand conditions, this is what we're seeing over the long term.

Yes, Dale.

MR. NESBITT: Can I make a comment? I think that's an important point. If you go look at the gas forwards ever since we've had gas forwards, the forwards themselves don't forecast prices, either. They forecast a zero arbitrage price as you go into the future, a respectable market average price that reflects the arbitrage decisions of everybody in the market.

And I think what these guys are doing is very respectable in that regard. I mean, if you think you can forecast a crisis in the year 2004, May, go ahead and bet on it. Because you're a lot smarter than the average ten million people who are trading in the market. It's really important, just go check out the Wall Street Journal over lunchtime today, and look where the gas forwards, the oil forwards, the gold forwards, the copper forwards, all those forwards are. They're smooth, sort of average effect of uncertainty abritaged out today, because we don't know how uncertainty is going to resolve in the year 2005.

And if we took this out of the context and put it in the forward market context, the forward markets are not trying to forecast future crises, either. And we don't criticize the forward markets, because many of those forward markets are terrific.

MR. PETERSON: Yes.

SPEAKER: I hate to raise this question, but since the forward markets I think are in the $4 range and have been about six or seven years, if you were going to make a bet, would you bet on the forward markets or would you bet on the model?

MR. NESBITT: I'd bet on the model. The reason I'd bet on the model, if you look at it empirically, and that's not facetious, I'd bet a lot. But if you -- that's not a facetious comment. There's been some studies done recently that I find compelling. What's the very very worst forecast that you can conceive of, of the spot price one year out? The very worst thing that you could've done in the last seven years is forecast the cash settlement price one year out. It's the worst thing you can do.

You know, that's not too satisfying, is it? Models have beat the forward market systematically.

SPEAKER: A lot of producers are selling into the forward market.

MR. NESBITT: You bet, but they're betting on information that departs from the forward market when the go long against the box. These are smart people. They have information bases that they think are better than the forward markets.

MR. BRATHWAITE: You know, if I may add something here. Dale, you know, I have a hard time with what you just said, you know. Because these people are putting their hard-earned cash on the line for those prices, and I do not believe that even though, you know, I use the model and I, well, you know, we produced these prices and that kind of stuff, and I believe in them, but I do not believe that we can do better than people who put their hard-earned cash on the line. They're willing to put their money where their mouth is.

So I'm, I'm not sure, I'm not sure I agree with what you just said. Thank you.

MR. PETERSON: We'll get, we're going to

talk a little bit more about this here in the next couple of slides, because this is a, seems like it would be an issue to be talked about a little bit more.

Before we get into that, let's go into some of the things we're talking about in the next forecast, which Leon has already talked about, but just some of that's going to be important from the price standpoint. And that is, new supply sources, or new information about supplies. For example, the USGS new information out here on the Rocky Mountain production region, how does that affect pricing.

Also, as we have already discussed, is the reserve appreciation factor; how do we incorporate any new information into getting a better information into the model and data. Last, and as Leon has already talked about, is the supply cost curve.

Last is some of the discussion topics I'd like to open the floor to. And we're starting to touch on it already, is NYMEX future prices, and to at least show some of the concerns that we have is, right now, we see futures as of this morning, their month was about 565. And if you look at our price forecast, just using lower 48, I believe we're looking at about 285, roughly. Obviously, quite a departure from our forecast.

Of course, our forecast is a long-run forecast, where these are short-run prices. The question comes out is, how do we use this information that NYMEX is providing to us, and is it something we should be incorporating into our forecast. If that is, we should go forward in that way, the next question is, is how. And looking to see if you guys have any input into that.

SPEAKER: Todd.

MR. PETERSON: Yes.

SPEAKER: Just an observation. You said short-run. I think NYMEX is pretty liquid out to six years or so, in terms of natural gas prices.

MR. PETERSON: Sure.

SPEAKER: It's getting more than just the next year or two years -- they're pretty liquid.

MR. PETERSON: Yeah. The question is --

SPEAKER: Their price is there, but it's not liquid.

SPEAKER: Where would you define the

product position?

SPEAKER: An open position. yeah, open positions throughout.

MR. PETERSON: Let me repeat the question. The question is that NYMEX pricing is going out about seven years, and that would be tending to go towards more of a long-run. And is that, is there enough liquidity in those prices to illustrate or help us out in our long-run price forecasting.

And there are some comments that right now, those pricings, those prices, contracts out in years 5, 6, 7, are not being traded real heavily. Looking at open interest numbers, I haven't looked at them recently, but roughly three or four months ago I was looking at less than 10,000 open positions. Whereas you look at --

MR. BRATHWAITE: But Todd -- I'm sorry.

MR. PETERSON: Yes.

MR. BRATHWAITE: I'm sorry. Finish. I'm sorry. I'm sorry, finish.

MR. PETERSON: Where you look at near month or six months out, 12 month strips, there's quite a bit more activity.

Leon.

MR. BRATHWAITE: Well, even though, I mean, I have to agree that the liquidity beyond, I wouldn't say three months, but beyond maybe a year, probably, is quite limited. I would agree with that. But those are still prices. Those are people still betting on, even though they, you are, I mean, you are five years out and you see the open interest drop significantly when it compares it a month out, those are still prices that people are betting their hard-earned money on.

So I think it will still give us some information, a lot better than no information at all.

MR. PETERSON: Thanks. Yes, sir.

SPEAKER: The other thing that's worth pointing out. I looked at the price of a 12-month strip on NYMEX, and a few days ago the average price over 12 months was over five bucks. So, and, you know, that's like more that $2 above your wellhead forecast. If you take that $2 and spread it out over five years, which is the model, you know, you still have a 40 cent average price increase just from this year alone. And the industry is expecting next year to be worse than this.

So you've got to deal with it somehow. If I were, if I knew how, I'd be out there paying my own hard-earned money, you know.

(Laughter.)

SPEAKER: But we, we have to, we have to find a way to take whatever the market is considering and factor it in to get anything that's going to be real. Happy to work on that.

MR. PETERSON: Thank you. Yeah, we're, we are looking at if this is the way to go, about using these NYMEX prices, then the next step is how do we do it, and make it as rigorous as possible.

Yes, sir.

SPEAKER: Anybody who's on the energy interest sucker list on the Internet has been receiving, roughly once a week, an invitation to come to a meeting where they will discuss the coming natural gas supply crisis. So there are a lot of people who think that, at least they convince others, that there is a coming crisis there. And obviously, if I just spent $5 or $10 million drilling a well, and I'm pretty sure it's going to last a while, I'm going to be selling some of that product out there just to get some cash flow to recover all the money I just put in.

MR. PETERSON: Thank you. Any other comments on coming prices?

SPEAKER: Do you think it's all hype?

SPEAKER: I don't think it's all hype, but I think it's --

MR. PETERSON: Are there any other comments on the crisis that is supposedly coming, as we probably all received e-mails on.

SPEAKER: Who has not received that e-mail?

(Laughter.)

SPEAKER: But I, just an aside, I did get a fax yesterday from Mid-America, that they are taking seriously, there was a press release yesterday from Reuter's with respect to that, was projecting $8 gas by the end of February, because of the cold. There's a lot of people out there that are taking the numbers seriously whether we do here, or not.

MR. BRATHWAITE: But, if I may add something, even if we do have $8 gas in February, it's still a short-term phenomenon. I mean, it's not going to be something that, I mean, unless somebody is saying there is going to be a fundamental shift in the marketplace, it's just going to be a short-term phenomenon. So I, I still don't see --

SPEAKER: Well, see, my point is that those numbers are high enough that they affect the annual averages, just like the slide that we saw.

MR. BRATHWAITE: Sure. Yes.

MR. NESBITT: I have one quick comment on that. If you're a driller, you're going to go out and set up an oil and gas drilling partnership after this meeting because you're so thrilled with the prospect of making all that money. What do you think? Are you drilling into forward curve? Are you like Carl, you're just going to go sell it forward? That, that price can wiggle on you a lot.

I mean, we're sitting here right now in a year that was colder than hell in the fall, and it's really cold today. It's really cold all over the country. We all know that you have strong non-linear effects from cold.

The other thing we have, I was just chatting with Bill about it, we have severely backward dated oil price. I don't like severely backward dated oil price if I'm trying to gain value from storage. In fact, it drops the pH in my stomach a lot, severely backward dated oil price. And so I don't store into it. We saw that in the year 2000-2001, the halcyon days of the two nasty red curves, one at Topock and one at Permian. And in Transco Zone 6, in New Jersey. Severely backward dated oil price really irks you in the winter, because people won't store into a backward dated oil price if they're rational.

So a lot of these short-term phenomenon that you're talking of, it's not represented in the long-term model. These guys I think have done due diligence on what do you drill into in the long-term and how does that form long-term prices. But when you get into these short-term validation and then making month-to-month, and if you really want to talk you've got to go day-to-day right now. A month's not short enough.

Daily gas prices, there's changes going all over the map. I don't believe month-to-month, it's no good. Oh, gosh, you can't do it, it just doesn't reflect reality. That's crazy.

MR. PETERSON: Sean.

SPEAKER: Great segue, Dale. I've been

thinking about the choice of making five years the default resolution of this particular model run. And would it be beneficial to do exactly what you suggest, shorten that period, get whatever resolution you can get, to more closely mimic what the futures prices are looking at. It also speaks to basis differential. You mentioned the peaking pipelines that have been built recently. That won't be caught with this kind of resolution.

MR. NESBITT: Good point.

SPEAKER: If you did that could you build in storage and what happens in storage? That's what's driving current prices, some fear that storages can reach some critical level.

MR. PETERSON: Well, on this, this model here is the long-term model. And on an annual average basis, you would think that storage really isn't going to matter a whole lot. And then if you pull that out over ten years, it seems like that's a fairly valid assumption.

Dale also has his short-term market builder model, which does include storage. So there is that kind of work which is pulled into more of a monthly granular, granularity, instead of this annual or five-year granularity. Which kind of pulls back in to Sean's comments here about bringing in better granularity, annual or monthly, or something of that nature.

Yes, Dale.

MR. NESBITT: Relevant to that question, what the MPC is going to do, it looks like now, is go ten one-year increments out, and then like five two-year increments and like five three-year increments. So they're going to, they're going to do what you suggested, compress the timeframe in the near term and then extend it as you go into the murky future. I think that makes a lot of sense.

MR. PETERSON: A think a question that comes up then, in my mind, with that kind of granularity, is are you going to make any determination between the next few years as the short-run, and then later on as the long-run, and how do you transition through that, which I think then brings us right back to this issue we have, is the NYMEX futures. If we're going to use NYMEX futures prices in the near-term, how do we pull that short-term pricing information into a long-run price forecast?

And again, that comes back to my

question of how.

Yes, sir.

SPEAKER: Todd, you're really making a distinction about futures prices that I think is misleading itself. Do you use prices, current prices in the model? I believe you do, right? So if you're bidding 1997, does it use current spot prices?

MR. PETERSON: Right. The question is, are we using current NYMEX data, or spot prices?

SPEAKER: If you use the spot price --

MR. PETERSON: No, we don't use the spot prices. What --

SPEAKER: -- 1997, does it matter what the price was in 1997?

MR. PETERSON: What we were doing in 1997 is we balanced the market, or, in other words, calibrate the market using supply and demand information.

SPEAKER: And it gives a price and how well it --

MR. PETERSON: It does provide a price.

SPEAKER: But you asked --

MR. PETERSON: I would have to go back to see how that is. But because the model is more forward looking and then comes back and resolves equilibrium over space and time, that price and quantity data in 2002 will affect the 1997 pricing.

SPEAKER: I just want to emphasize that there's not like there's futures prices and spot prices. They're all one set of prices, and so if you calibrate in part, you should calibrate them all. Or if you don't mind not calibrating the part, then you shouldn't be calibrating any. And so judging this kind of model isn't whether it fits the current situation or not, because those are going to be showing the short-run disruptions that are part of these markets.

MR. PETERSON: Right.

SPEAKER: You just want the long-run, fine, that applies to spot prices as well the futures.

MR. PETERSON: That's something we'll have to think about, understand better. Thanks.

The next issue we'd like to talk about is how do we use prices, from an absolute sense, or a relative sense. And again, we started to touch on this and tried to show that from a relative sense on the WECC electric generation graph. And also, we've talked about basis differential. And in the next report that we're looking at, the outlook 2002-2013, we're looking at putting more information about that basis differential. Seems like that's something that's important to understand how infrastructure will be built in the later timeframes, which we've already touched on.

And the current price environment, and how will that possibly influence market developments, meaning what kind of supply and demand responses. And we've touched a little bit on demand and we've talked about industrial demand, demand destruction, if it's chemicals or pulp and paper, aluminum, et cetera. This is something else we're going to be looking into, as we've already talked about.

With that, I'd like to open up the floor to any other discussion matters. Yes.

SPEAKER: A question. On your price trajectory for Kern River versus El Paso, you've got a differential there that, I guess it's cost-based, for assessing the cost for expansion, right?

MR. PETERSON: Yeah. The question is,

the differential that we have on our WECC electric generation price, the El Paso, I believe it's the El Paso North has a differential compared to the Kern River to California price. And is it transportation based.

Mainly, it is a commodity -- well, it's a little bit of both. It's commodity-based, but also there is some transportation costs going in there. As we need to expand the pipelines, as Leon has talked about, we are adding in a transportation cost.

SPEAKER: Okay. So is it, the numbers, both for entry points to the SoCal system, their opportunity cost, saying they would tend to equilibrate; right?

MR. PETERSON: Yeah. When you get to the California border, what we are looking at are price-taking behavior. So you would see the El Paso North, this projection is correct. Prices coming off of Kern River would equate to the prices coming off of El Paso North at Topock.

SPEAKER: Okay. Assuming there were no other constraints that would tend to create a price differential. Now, did the resources, electrical resource plan, I notice we had 18,000 megawatts added in California, and there was a statement describing that, the lower gas price, and it comes out that the Kern River is a big determining effect; right?

MR. PETERSON: Right.

SPEAKER: So if this price differential didn't exist, then all that development around, all that capacity, generation capacity being added because of Kern River having more price in the model, that's really it.

MR. PETERSON: Well, we want to remind ourselves that this price of Kern River to California, this is more upstream on the pipe than here, more towards the north Needles-southern California area. We would probably have to talk a little bit more to David Vidaver about what kind of constraints might occur as you move more towards California from, either from the southwest or from the Rockies, and what kind of constraints may be involved, mainly from a transmission standpoint.

Yes, Brian.

SPEAKER: Probably a nagging question on my part, but, you know, all the prices seem to be increasing about 20 percent or so in the ten-year time horizon. What, generally, do you attribute that price increase to?

MR. PETERSON: There's two things, generally, I would attribute these prices. And, yes, you're right, it's about a two percent annual growth rate.

First is the supply costs moving, marching up the supply costs as we harvest more, more natural gas. And secondly, as demand grows in certain locations it's the need to increase pipeline capacity to deliver, and the associated cost to expand pipeline.

SPEAKER: And this is a different trend from like the last ten years, or the ten years before that, where the system was expanding, moving along some aspect of the supply curve, new pipeline being added, but prices were generally declining.

MR. PETERSON: Right. Well, what we did see, one of my previous graphs will help illustrate that. Here, is in the '90 through '96-ish timeframe, a lot of folks talk about the gas bubble, meaning there was quite a bit of supply available to the market. And as that gas bubble has been worked off, we're seeing pricing stabilize and possibly increasing here over the, the foreseeable future, from the modeling standpoint that we're taking.

Any other questions, comments? Yes, Dale.

MR. NESBITT: That's a good comment. One comment that I heard just the other day, I mean, you know, if you go back to 1985, this guy was saying there's three kinds of steel in a gas well; there's horizontal steel, vertical steel, and steel on the surface. Back in '85 there was no horizontal steel. We didn't even know what that was. There was no three, four, five, however many dimensions you go. Seismic, we didn't even know what that was.

One of the things, in retrospect, there was a heck of a lot of technological innovation and cost reduction and depletable resource production that happened in the interval, let's say '85 to '00. The really tough question out there, and these guys will talk about it on the reserve appreciation, is you're going to project continuation in that trend, and we've got horizontal steel everywhere now. Or are you going to get on a depletion curve.

I'm hearing more and more these days people in industry talk about getting on the depletion curve. I don't know if that's right, but that's what they talk about. So I think a lot of what you saw for 15 years prior to the eighties was technological progress offset completion. Probably more than offset it in certain places.

Those are really gut level, tough problems.

MR. PETERSON: I think that comes right into what Leon brought out as issues to discuss, is how do we, how is the technology change going to affect supply cost. So I think it's an important question. Do we use history as our guide, or is there some other information that is out there to help us out?

Cy, please. Okay. Carl.

MR. FUNKE: There's actually, apparently, a lag factor to the reserve appreciation now, because suppliers are not drilling when they get the high price signal until they are more sure. I don't know if that's, we want to think about that, but.

MR. NESBITT: There's a study out of Rice which is interesting, they just did this.

They were asking the question, statistically, what does volatility do to investment. And they found a, you know, you've got to have three quarters of a point, or some number like that -- don't quote me on the number -- more return on average to compensate for the risks. So one of the theories that's coming out statistically is that volatility in gas markets has caused a little bit of retardation in economic activity. You'd expect that.

The issue is, you know, this is, you know, one data point. But the issue along those lines, you know, there's a lot of volatility in technology, you could probably get a lot of different people in the room voting differently on technology with some volatility now on an issue that was pretty lockstep certain in 1992. Everybody was shooting seismics. That's the way it was.

SPEAKER: Would the model, would these prices in the model tell you at what point you begin to see a significant increase in drilling activity? Because it doesn't seem to me that despite the current prices there has been much of a response.

MR. PETERSON: The question is, with the prices that we see in the model, does it help invoke additional drilling activity.

Our supply cost curves have built into them drilling costs. So it's, it's not as responsive as you would see out in the real world in the short term. Prices increasing, and you get increased drill response, so our drilling rig information is embedded into the supply cost curves.

Yes, sir.

SPEAKER: Todd, I might make a couple of observations. One of the areas that hasn't been quite as prolific and we've seen a lot of increase in production is in the San Juan, it's in the Powder River Basin in Wyoming.

Number one. Those rigs don't show up on the rig count. Okay. So if you're looking for any kind of indication of that activity, you're not going to find it.

Secondly, the prices that, the wellhead prices that producers have seen the last year, year and a half, have been very very low. We've seen some 30 cent prices in the Powder River Basin in Wyoming, and people are not going to drill at those levels. In spite of the fact that, you know, it may be at $4 or $5, we'd have huge bases.

So you can't just look at wellhead prices. The cost to drill a well is maybe 30 cents. The cost to add compression and deliver it to a market hub may be two or three times that. So you can't look at just wellhead prices. You have to look at hub prices, and the cost of transportation to get it to a point where it can be sold.

So I think that, in large part, explains some of the seeming paradox that we're seeing, because high prices, on one hand, at the hub, or at the SoCal border, and yet the seeming lack of response out of the production business.

SPEAKER: Since he mentioned coalbed methanes, is that in the model or not? I wasn't clear whether that was unconventional resources --

MR. BRATHWAITE: It is.

MR. PETERSON: Those resources are in the model.

MR. BRATHWAITE: It is, yes. In several, there is. In summer there is, San Juan, there is. In several there is, San Juan, Rocky Mountains -- where else. In Canada. Yes.

DR. GOPAL: We have a significant amount of coalbed methane in the San Juan Basin. There is some level of coalbed in the Rockies, as well as in some of the eastern regions. We have some in Canada identified as coalbed. The USGS has come up with a recent revision on some of these resource numbers, so we will be looking at those numbers for the next cycle.

MR. PETERSON: Cy.

SPEAKER: In discussing the new technology, there is a difference between the new technology and the other. Most of the technology data that I've seen invilves the S-shaped curve, so it really has indicated where we were. But we should know whether there's some new stuff coming along that will change things, so it begs the question.

MR. NESBITT: That's a good question. I'd commend to you the work that the Geologic Survey, Don Gartero (ph.) in Menlo Park, is doing on that. They're trying to get after that by looking at appreciation of reserves in the existing fields, because they think that's an important, partially technologically driven thing. They've done statistical fits on Russia, the North

Sea, the U.S., and those kinds of things. And we're only partway up the curve of application of known technologies, because that's what's in the statistical studies in a lot of these regions, they think.

The new technologies is a tough one.

SPEAKER: Seeing that you're interested in long-term pricing, which is our focus, that would indicate --

MR. NESBITT: Some remarks I'll make this afternoon. One of the things that they're finding, too, and this one, I don't think that the staple's all the way through the report here, I'll give it to you as a draft. Okay. That the phenomenon of appreciation of reserves in existing fields is a phenomenon of reworking historical production plus today's proof, not the future. The view is that whatever new technology is going to be applied, it's going to be applied to the future, wildcatting, exploration, and production.

The big pop comes from the Permian Basin, you know, wells that were started in 1910. Midway Sunset actually drove that first well in 1899, set a ten-year RP ration on it for 104 years. If you really think about that, somebody up there's making gas out of sackcloth. You know. The big guy upstairs said here's another TCF of gas, just because we like you guys so much, and here's another million barrels, just because well, you've been good in California.

And you've got to get after how that rose and at what rate over time, and it's a mish-mash of new technology coming on in spikes, and you can actually see spikes in the curves, historically. The hard part is, is there any subjective or objective assessment of new technology you can apply to that field, or is it truly depleted? Nobody knows. Big uncertainty, as far as I can tell.

MR. PETERSON: Any other questions?

DR. GOPAL: All right. What we will now do is break for lunch, and instead of the agenda's time of 1:00 p.m., we will come back here by 1:15. So we'll see you at 1:15, and if there are any other questions on price, supply and demand, we will probably take it up after the other two sessions are done. So at the end of all discussion, the whole panel will be available for more questions and discussion.

Have a nice lunch, and come back at

1:15.

(Thereupon, the luncheon recess was taken.)

AFTERNOON SESSION

DR. GOPAL: Okay, folks. I hope you all had a nice lunch. It's time to get on with the next item on the agenda. We are going to be talking about natural gas infrastructure. This issue will be led by Bill Wood.

A couple of things that I want to mention. You know that a lot of the infrastructure issues sometimes are sort of handled at once, you know, what happens tomorrow, what happens three months from now, and things like that. Gas pipes are added, storage is modified, et cetera.

Okay. Thank you. Scratch what I said earlier, then.

Bill Wood will lead the next session on the natural gas infrastructure, and before we start the session, there are a couple of things that I wanted to mention.

In the model, we are dealing with long-term type trends, what happens, you know, if a completely new pipeline is built, what happens if market demand goes up, do we need a new pipeline, is it economical, and things of that nature. But in Bill's talk I'm sure he's going to be talking not only about the long-term aspects, but also as to what happened in the last two years and three years, for example.

The other thing that I want to also bring up at this point is that we have a discussion also on the storage to be presented later on, and I would like to integrate storage analysis with the work that we are doing. Of course, I'm not saying I'm going to mix short- and long-term together, but I do want to address both issues because I think short-term analysis and storage has come to be more important and a very critical issue in trying to understand what's happening in the gas marketplace today.

So to that aspect of what we are doing at the Commission, is working with UC Davis staff, Professor Williams. They are working on developing a mathematical simulation model to represent storage. So they may be having some questions, too, in between that, to try and understand this market, exactly how it's functioning.

So, with that, I want to call on Bill Wood.

MR. WOOD: Do you want to push me up?

Hang on a second while I get myself organized here.

DR. GOPAL: I have been asked again and again by our court reporter that people who want to ask questions, if you could please come to that microphone it would be greatly appreciated. There is one right here. It'll help him in reporting who asked questions, and what the question was. Thank you.

MR. WOOD: First off, I'd like to thank everybody for coming out. The last time we held one of these workshops, which was about two years ago, I think we had the grand total of three or four non-Energy Commission people in attendance, and they were basically from SoCalGas and PG&E. At that particular time, this was a 1999-2000 timeframe, natural gas had kind of fallen to the side; nobody was that interested in gas anymore, you just kind of took it for granted, it was there. So there wasn't the big controversy that we had back in the late eighties and early nineties, just prior to building the new big pipes that came into California.

So it's great to see the big cross-section of people that are here today.

Secondly, when I'm finished I think I'll ask Curt Morgan to come up first, since we're doing all pipeline stuff, and then we'll ask Chris to come up with the talk about the storage issues and his presentation, after that. So we can close it off in that manner.

Okay. Basically, I'm going to be covering four areas here. First, utility infrastructure, the way we see the infrastructure requirements will be during the next couple of years. Then -- during the next ten years' horizon. And then we'll also look at the interstate pipeline infrastructure needs serving California, again, during that same period of time. I'll briefly describe some of the LNG facilities that are being proposed along the west coast, and then pull together a couple of conclusions.

And hopefully this all will pull together and spur a number of questions from you, and also not only questions, but information from you, because, again, we're looking for information from you and our work here is only as good as the information that the industry and interested parties have in providing that, and keeping us up to date with what's going on so that we can apply that, then, to our work here at the Commission.

I think we're fairly well-known for having an open mind and having thick skin and being able to listen to what people have to say, and then incorporating that into our work; that is, to the best that we think that it fits in, and you can convince us that it fits into the system. And normally we're pretty open-minded when we receive information from individuals and from the industry.

Our first figure that I want to talk about is the PG&E infrastructure. Here I've actually shown the natural gas demand that we have been using in our forecasts, and comparing this to the receiving capacity that we see -- oh, thank you, Jairam -- that we see that's going to be needed, the receiving capacity we see that's available on the PG&E system.

Receiving capacity, of course, is up here. This represents about 3400 million cubic feet per day, and includes the 200 million cubic feed per day new capacity that PG&E added this last year. It also includes a couple hundred million cubic feet per day of California production.

The forecast indicates -- first off, let's explain a couple things here. Here we see residential, commercial, and industrial forecasts are fairly stable for the next ten years in the PG&E service area. This is electric generation requirements, and we prepared these in conjunction with the California Gas Report, using California Gas Report assumptions back last spring. My understanding is that our electric generation demand forecast isn't that much different. There is some differences, but it isn't substantially different than what PG&E came up with.

Now, these two figures that you see here, the lower one is deliveries from line 300 into the SoCal system at Wheeler Ridge. Basically, that is Southwest gas coming into the, into PG&E's line 300 at Topock, and then being moved to Daggett and then into the SoCal system.

The line 400, or the L400, or 401, is Canadian gas coming down the PG&E system from Canada, off of TTN and being delivered, again, to southern California via, probably through displacement, into the SoCal system, again, at Wheeler Ridge.

Now, let's talk about the differences that we see here between our annual average gas demand and receiving capacity. During the last few years, there's been a lot of discussion about how much receiving capacity you really need on a system in order to meet your seasonality difference, coupled in with pipeline capacity and storage. A number that has been batted around is like having 20 percent excess capacity on an annual average basis to meet your swing demands in the wintertime, and coupling that, again, with your storage availability.

Well, our forecast indicates that PG&E fits into this area until about 2007, at which time they hit 20 percent capacity, or slack capacity, and then by the end of the horizon here we're seeing them in the area of about ten percent of meeting, having slack capacity, indicating, then, under these circumstances, that there is a potential that new infrastructure, receiving infrastructure, is going to be needed into the PG&E service area.

Now, we've identified about five different possibilities here that could be done. And none of these, only one of these were actually included in our initial analysis, or the analysis that we've used now. That has to deal with increasing the receiving capacity in line 300 and line 400, from interstate pipelines that deliver gas into California and into the PG&E system.

But there are a couple other alternatives that also could be used to meet those requirements. One would be an additional Mojave expansion. Remember Mojave about ten years ago, or eight years ago, it proposed moving a pipeline, or extending their pipeline up the San Joaquin Valley into the Sacramento area, and then across over into the Bay Area. Well, that's one alternative that could be done to meet this additional requirement.

Also is El Paso has proposed the Ruby Pipeline to come from, it's in what we call the Interstate 80 corridor pipe that would come from the Rocky Mountains across to Reno, and then down into the Marysville/Yuba City area, and then into Wild Goose and then potentially on into Line 400 for PG&E.

An additional option which apparently may be dying at the moment, and that's LNG, at least there was a proposal at Mare Island, and one of the proponents for that has backed out on it, but it isn't completely dead yet, though who knows what'll happen in the next, next month.

And then, finally, is increased California production. I talked with Jam Campion from VOG regarding this, and it's hard enough for California producers to maintain current production, let alone try to increase the production. So that one doesn't seem too very likely at the moment, though it is an option that could help meet the future requirements for PG&E.

Here we see a similar program, or similar chart for SoCalGas service area. This includes San Diego's gas requirements. Again, res, commercial, industrial are very, very constant, with just a slight increase in demand. Our forecast for electric generation in the SoCal service area is slightly different than what SoCalGas used in their forecast. We actually show a higher gas demand here than they do. We assumed more capacity being built and utilized within their system, while they have assumed more gas, or more electricity generation outside their system, importing that into California.

So this indicates, then, an importance

in understanding where electric generation is going to be built, because it will have an impact, then, on the infrastructure requirements that will be needed to meet future gas requirements.

With regards to receiving capacity, we currently see them at about 41 percent, dropping down to about 22 percent out here, so this includes the expansion that they went through last year, the 385 million cubic feet per day multiple, or the total expansion that occurred.

So our estimations at this point, given our forecast, is they have plenty of receiving capacity within their system, within the next ten years, giving this, if you live by this 20 percent rule.  Without this capacity additions, they would've been here at 3500 million cubic feet per day, and under those circumstances, they would've been in a similar position as PG&E is now.  They would be operating at about 27 percent, dropping down to about 22 percent in 2007, and then going down to about ten percent by 2012.

So therefore, they have added the capacity they need for the next decade earlier than PG&E has.

Let's see, is there anything else.  I

think that's enough.

All right. Now we're going to talk about interstate pipelines. As Leon indicated today, we look at pipelines by corridors. So in this case, I'm using an El Paso pipeline, but it pretty much represents, on this portion, this is the El Paso North, but that also, in our model, represents also Transwestern and also Southern Trails pipeline, which just came into operation last year.

So this, then, represents those three pipelines. Down below, we see El Paso South, and then we also see another important pipeline in their system, as far as California is concerned, is this line right here. It's called the Havasu Crossover. Basically, that's a two-way, this pipe is a two-way pipe which allows gas to either flow north or flow south. But for the most part, it takes gas from the San Juan -- it receives gas from the San Juan Basin that flows this way, and then down, then the gas can flow this way or it can flow east, or it can flow west, into southern California at Blythe/Ehrenberg.

Now, let's talk a little bit about the demand that see that's occurring within this area.

We talked a little bit about the electric generation requirements there this morning, with David Vidaver. He indicated something like in the area of 13,000 megawatts is being proposed. Most of them are right here on the El Paso southern system. There are a few of them up here, plus there are some, also some across the border in Mexico.

In addition, so we have this great amount of new generation that's going in here. The North Baja pipeline actually starts right there, it comes down across and serves, then, Rosarito Beach, as well as two power plants that are being built at Mexicali. What is there, in the area about 2,000 megawatts that are about to come on in this general area.

So one would presume that this El Paso South would be really running heavy out of the Permian Basin. But if we look over here at the, at El Paso South, the first bar that you see here, the first column that you see, is our understanding of what the capacity is, mainline capacity is on the El Paso system.

And as you see, our forecast, basically just on the configuration you see here, without any new additions other than what occurred this last year, that is, Red Rock and Southern Trails coming online, that if the model represents the market, then the market does not want Permian gas, because El Paso South is running below capacity and only gets up to about 80 or 87 percent capacity ten years from now. And this does not include the All American Pipeline that is in the process of being converted over. This capacity does not include that.

What does the market, according to the model, want? It wants the San Juan gas plus any Rocky Mountain gas that can come down this way, come cross and down. So basically what we see, then, is we see El Paso North Transwestern, that's this piece right here, this is the existing capacity, and this is the build-up that it is looking at for that particular pipeline system.

You can see that there is in the area, let me see, a growth rate of 25 to almost 50 percent additional capacity needed on the El Paso North Transwestern corridor. That is to move gas this way, and then the Havasu Crossover, which will be principally the movement of that gas to get it down here, as well as into the North Baja pipeline, is going to increase in the area of five times its existing capacity.

Some have said, well, then what about moving the gas this way and around here? So, and actually, the model is doing some of that already. But this is what the model tells us now is occurring in the model, that the San Juan Crossover, that's this piece right here, is all running at capacity and additional capacity. So in order to meet this capacity requirement, you either have to beef up that or you have to beef up that to bring it down to make use of the All American Pipeline that is in the process of being converted.

Now, with regards to new alternatives that have come into play during the last six or eight months, there are a number of them. Let me walk through those.

SPEAKER: Before you go on, a question about the model. In order to get that capacity, the model has to assume that Havasu and El Paso North were going to be expanded according to some coast thing?

MR. WOOD: Yes. The model has a parameter in that there's a cost structure that says that if you go up to 100 percent it's one cost structure. If you go above 100 percent, then you start adding cost onto the system to help pay for any additional capacity that will be needed, in order to meet that new capacity requirement.

Leon.

MR. BRATHWAITE: Just a slight clarification. Your model does not assume expansion. It just allows it to expand if it's economic to do so.

MR. WOOD: All right.

MR. BRATHWAITE: Just to be clear.

MR. MORGAN: Bill, one other question. This has got to assume, then, that there's an incremental Bcf of gas in the San Juan Basin to come on the El Paso South corridor?

MR. WOOD: That is, well, it's either coming from there or it may -- I never looked at, never went this far with it to see what's coming here. Because there is, Northwest is coming down, and what's this other pipe that's TransColorado also is coming down. I didn't look to see what that corridor is doing, but there could very well be gas coming down this way. Because basically, as you, we saw earlier this morning, whether you agree with our prices or not, basically the differential between those prices generally hold fairly close. Whether they're exactly right or not, those prices, those differentials hold.

So basically, what it's saying is Rocky Mountain gas is cheap, San Juan price is cheap, that's expansive, that's expansive as far as California is concerned. So therefore, the places that California wants, the market wants to get gas, as far as Southwest is coming this way, are that production.

Now, as Kirk, I'll have to look to see, but I probably will hold off because we're in the process of doing additional runs. But I'll look to see what happens there.

But our forecast for San Juan Basin indicates that it does, it will hold up during the next ten years with regards to meeting requirements. In fact, I just saw something that USGS has added another 20 trillion cubic feet of potential resources within this area. We'll have to look to see whether, where those are and what they are, and whether we want to include those or not in our new forecast.

But getting to the alternatives now, one of them that was, came out at a conference that I was at earlier this year, was from El Paso. Basically, they said they'll extend the All American Pipeline from here to Daggett, which is right about there. At that point, Kern River comes down, and they can then pull gas off Kern River, which is Rocky Mountain gas and it's gas that people want in this area, and then they can backhaul it to this area to meet this additional requirement that's in here, or back into the Mexico area to meet the generation requirements here.

So that's one requirement. The pipes are already there. That's an easy, that's an easy conversion.

A second one is one that Sempra is proposing, that has kind of been included in here, and that is an expansion of the Havasu Crossover, but Sempra's proposing the Desert Crossing, which would come up and then come over here, and also put storage in this general area. They would basically then be building up the Havasu Crossover as well as tying in to Kern River.

So they would then be able to -- the Havasu Crossover as they are the -- the Sun Desert as they perceive it, then it would take Rocky Mountain gas off Kern and it could also take San Juan gas off to bring down to feed this market.

What else did I have. Another one that has been around for awhile, for the last year or so, has to do with LNG in this area. At least one LNG potentially will be built in this area. Depending upon its size it will be able to meet the generation at Rosarito Beach, as well as Mexicali. It could be big enough to move some gas across the border into San Diego. It could also be big enough to move some gas backhaul on the, on the North Baja Pipeline to Ehrenberg, or it can flow back here, or maybe swing around and come back into California.

The capacity of moving gas across here is already there. It just needs a presidential permit from, for Sempra to file an order to backhaul, or bring gas from Mexico into California. They could do that starting tomorrow if they had the presidential permit, because the Baja is already moving gas.

Yes.

MR. EISENMAN: They don't have a tariff to do that, either.

MR. WOOD: Okay. So they need both of those things, then. Okay.

MR. EISENMAN: Or a rate.

MR. WOOD: Or something.

MR. EISENMAN: Well, it's all of the above.

MR. WOOD: Yeah. Okay.

All right. Two more proposals I just came across this last week. I've been on vacation for three weeks, and I just got back. One of them is Kinder Morgan just announced its pipeline to basically build from this area over and then down into Phoenix. That is basically a combination of beefing up the El Paso Transwestern corridor here, as well as a little bit of the Havasu. And they also are talking about two additional, associated with that would be building additional capacity to bring them more gas down from the Rockies.

And then the final one that I'm aware of is Texas Pacific. They've been around off and on for awhile. They have a big, they have right-of-way, apparently, that's right along the El Paso South system, and they're talking about a Bcf a day pipeline that would come from here to Ehrenberg, and help serve this area. But its source of gas, again, would be the Permian area. And they say they've signed up 600 million cubic feed per day, but I haven't seen anything more than their press clippings on that, so I'm not certain what's happening there.

Okay. So that does it for El Paso. Let's see, did I have something else I wanted to say here. Oh, other than, yes, this does include the recent conversions and additions of pipeline capacity inside, along this particular system.

Kern River. Kern River starts in the Rockies, comes down and comes into the lower San Joaquin, San Joaquin Valley, where it bifurcates and goes on the east side/west side, calling the Kern Mojave Pipeline system. This is a, this was put together by Kern River a couple years ago to kind of show where the generation is being proposed. I haven't kept up to speed with how much of that is still there. Some of it has been, probably has backed off at this point, but yet Kern River does have capacity sold for its big expansion that's going on.

Oh, it didn't get the years on -- oh, well. Seems like there should be. Anyway, this is the existing capacity as of 2000-2002. This includes the 145 or so million cubic feet per day that Kern River added onto their system last year. We show them kind of dropping a little bit below that. This is pretty close to what's happening. I think I summed up something, some daily data yesterday, and came up with California deliveries of about 672 and, and I think they're probably closer to about 700, or a little bit more than that, total deliveries to the, you know, to, say, to this general area. So this forecast is fairly close.

By the way, with regards to our forecasting, I want to point this out. When we first started using this model in the late eighties and early nineties, we found that there was a tremendous amount of gas coming out of the San Juan Basin, and it all wanted to flow to California. And I called El Paso up and I said, can you reverse the San Juan Basin -- or the El Paso, or the Transwestern -- or, come on, guy, brain -- the San Juan Crossover. And they said yes, they could, but at that particular time it was just a one-way flow. It just flowed west.

So we put it into the model, and it filled up not only its system, but also the

Transwestern system. Two years later, El Paso reversed their pipeline, and a year later after that, Transwestern reversed their pipeline. So basically, the model is telling us the kinds of things that would happen.

Another more recent, when we did the evaluation of Kern, Mojave, and the GTN expansion, our model basically said Kern and GTN were mutually exclusive, that they were added in in terms of benefits for California, and that the Mojave pipeline, which came from El Paso Transwestern at that, the time it came in, would probably only operate at about 50 percent capacity.

Well, guess what's happened. The GTN is running full, or fairly full, Kern River is expanding, and Mojave is running at about 50 percent capacity. The model told us that ten years ago when this was being proposed.

So, is our model working? I think it's giving us a good indication of where the market wants to go for gas, and what I'm trying to do is indicate that here.

Now, at this point we see, this is going up to about 1800 million cubic feet per day, and that's pretty close to the expansion that Kern River will have in place by the end of May. So basically, Kern River is building to meet this requirement at this moment, and then in the next five years after 2007, another 300 or 400 million cubic feet per day will additionally be needed. And I'm sure that they'll be in there trying to make that expansion.

This is the GTN. I asked Eric to put this together for me, or at least he sent it to me,what, about a year and a half ago. This, again, shows the GTN Pipeline, also shows Northwest Pipeline, and then a number of the proposed power plants.

Now, one of the things -- oh, one of the things that David had indicated is that the growth in power generation up here is slacking off. Two years ago, GTN was talking about a lot of expansion, maybe up to a Bcf a day during the next ten years. But because of that back-off in expansion, as well as the loss in roughly 3000 megawatts of generation needed to meet the aluminum requirements, this generation is not apparently moving ahead as fast as it was. In fact, GTN backed off, or announced that they weren't going ahead with their next announced expansion because they couldn't get the demand, or the demand wasn't there to support it.

So basically, our model, again, is telling us something similar, based upon the forecast, the electricity demand forecast that David provided to us last spring. Basically, this is, again, existing capacity with the current expansions that have occurred as of 2002, and this, we see then, is the growth in demand. And basically, we see by the end of the next ten years, actually during the next five years, there may not be much need for additional capacity, but within the next ten years, as far as capacity delivered to Stanfield, which is right here, there will be some additional capacity requirements.

And then, as far as Malin is concerned, now, Malin is right here at the California border. Gas comes from Malin into the PG&E system, but it also, there's a line that comes down called Transwestern Pipeline that delivers gas into the Reno area. They've just gone through an expansion. What are they, 125 million cubic feet per day, or something like that. And so we have these two things coming off. And so the difference between here and here represents, then, what's going into, into Tuscarora. But again, there is some capacity generation, or capacity, additional capacity needed at Malin, but not necessary to meet the PG&E requirements, but to meet, apparently, the requirements that are occurring here, and maybe here at Medford -- or, yeah, Medford here, and coming down south, and to meet the new demand in Reno.

I'm going to shift now to LNG. We've listed nine projects here. In northern California you have the Bechtel Shell. Now, Bechtel, or Shell has backed off, saying for, for different reasons. Bechtel is still in there swinging, but there was a feasibility report, or a safety environmental report, I can't think, that was just published, and that's going before the city of Vallejo early, or within the next week or so. And I, maybe the fate of this facility will be decided at that point.

As far as southern California is concerned, the leader at the moment in that area is the Mitsubishi LNG facility proposed at the Los Angeles Harbor. They've been doing grass works work there for the last year and a half, and have filed something with the Port Authority. Supply for this will serve southern California, and possibly displace east of California supply, as well as some Rocky Mountain supply that flows into southern California system.

Crystal Energy is looking to use, I believe, a Chevron platform, an abandoned platform that's off the Santa Barbara/Ventura area. It would basically serve California. We're not certain what's happening here. We haven't heard anything from them for awhile.

And the, of course, in southern, or in Baja California, there's about five here, and I think Eric indicated there's six. Let's see, one, two, three, four, five -- yeah, I got six. Okay. So basically, we have at Rosarita Beach, El Paso and Phillips. Again, all of these will basically serve the demand, the generation demand in Baja California, as well as the potential to move gas into California via San Diego, or backhaul off using North Baja Pipeline to move gas into either east of California sources or back into California at Ehrenberg.

Let's see. Three of these have filed for a permit from the federal government in

Mexico. I know that Marathon and Sempra and Chevron, those are the three that have filed. My understanding is one of the, one of those project's permitting is imminent, that they may be getting something very shortly.

And I indicated early I wasn't going to talk today about the, our little study, but I already did that this morning and I'm not going to go any further into that, other than that.

Okay. The overall, if you were to total all of these up, you're roughly in the area of six Bcf a day of capacity, or of new capacity in LNG. And, of course, not all those are going to get built. I would presume one or maybe two might be in our near term future, the next five to ten years, but I won't go any further than that.

Okay. Here, conclusions. I see, based upon our NARG analysis, that there is going to be additional pipeline capacity to meet growing gas demand throughout the western states. PG&E, looks like, will have to do some additional beefing up in their receiving capacity within their system, but SoCalGas looks all right, using the criteria that I was using, to meet the requirements for the next ten years.

What's driving that demand principally is natural gas supply needs. And that was illustrated both on the PG&E and the SoCal slides that I showed you, but it also is relevant for the Southwest, as well as the Pacific Northwest and the Rocky Mountains. The electric generation, whose fuel is natural gas, is driving the gas demand in the western states. And as David indicated this morning, and I want to emphasize this, it's not the number of power plants that are being built that drives that gas demand. It's the demand for electricity that drives the gas demand.

So if you, you can over-build by 100 percent, your gas demand isn't going to increase any. It's going to remain at approximately the same. And on the other hand, if you under-build, well, then you might have some problems because you may not have enough gas to meet your requirements, or electricity to meet your requirements.

So, again, electricity demand is what drives it. I remember I was in Wyoming and I told the guy that we were proposing, you know, 10 or 12 or 15,000 megawatts of generation proposed for California, and his eyes just lit up because he said, oh, that's all that gas demand. But the thing is, even if they build all of that, the gas demand isn't going to be any higher, other than what the need for electric generation would require.

Okay. But the important thing here I hope I've indicated, is where and when the power plants drives the need for infrastructure. David indicated that there's a lot of generation being proposed in the Southwest. And that is dropping off from the Pacific Northwest. And that, then, is going to drive the need for infrastructure within those two regions.

Now, if there is not enough, if California builds a lot of natural gas demand within the state, that doesn't, that means then we have to build the infrastructure in order to meet that gas demand. If, again, if the electric generation is built outside the state, then that infrastructure isn't needed inside the state to meet the requirements because it's going to be imported, provided there is enough transmission capability to bring it in.

So when it comes to David using his crystal ball with regards to where these new power plants come into play, it's very important that he had some sort of basis to make that assumption, those assumptions. And if you've got any thoughts on that, I would really strongly suggest that you attend that, what is it, February 25th and 26th.

That's in February, yeah. You attend that particular session to give your input into those assumptions with regards to where are these power plants going to be and what is the timing for those new power plants. Because that, as far as our infrastructure requirement, that's very, very important.

And, of course, then there's a lot of interest in LNG in the west, and the west coast. More than likely, there will be at least one built sometime in the near future, the near future being ten, five, ten years timeframe.

Again, to go back to the questions that I have posed. Does, have I covered all the projects? We will probably, in our next analysis, will at least run scenarios with some of those different things. Some of them we've already covered, or included, or partially included in our analysis. But for instance, the All American Kern River tie-up at Daggett was not included. I think that's something that would be good to do. We partially did the LNG one in our quick and dirty analysis. We need to clean that one up and do that one again.

I think we've taken care of the Texas Pacific one with our analysis we've already done. And the Kinder-Morgan proposal I think has sort of been included in our analysis already. But we haven't really done the Sun Desert one in its entirety, so we might actually do that additional one by itself.

Any questions or any input with what we have done here? How does this forecast hit you, you know. Does it seem reasonable, does it fit into the area that you're thinking, or is it kind of off the wall, and you're thinking maybe this isn't right, maybe there is going to be more generation someplace else, or the demand is going to be greater someplace else.

So that kind of information is what we're looking for. Any discussion, any questions? I'm getting dry, so hurry. Yes.

SPEAKER: Well, it's my understanding that you haven't incorporated gas in the demand, the new renewable requirement for 20 percent of sales which come from renewables. How much do you think gas demand will be affected when you update the demand with the requirement for the --

MR. WOOD: Well, David indicated that's going to be about 2000 megawatts. And if you assume a thousand megawatts burns about 189 million cubic feet per day, using a heat rate of about seven percent on a half thousand Btus per kilowatt hour, that throws you somewhere in the 300 million cubic feet per day area. But, remember, he also said some of that is wind, and it's going to require some backup on it. So therefore, you're not going to save at all.

Any other questions? Don't tell me I covered every -- yes, Eric.

MR. EISENMAN: You mentioned the possibility of Mojave and also the Ruby line, both entities proposed by El Paso. And I, I would suggest that given the relationship between the State of California and El Paso, that the chances of either of those happening are quite low. Maybe from a commercial perspective they might make sense, but the reality, political realities, I don't see any, I don't see El Paso wanting to invest that kind of money in this state. That's one point.

Second, a question. You have increases in capacity on, on the El Paso TW and Southern Trails line, and also the Kern River line. How do you see the split of that increase between northern and southern California? Do you see PG&E having to expand line 300?

MR. WOOD: Okay. All that capacity increase that we see on the -- let's go back. All that capacity increase that we see here, that's to meet this requirement and this requirement. If, I don't have the graphic here, but basically we see Southwest supply coming into California pretty steady. Running at about, I don't even remember the numbers, but it doesn't, it drops off from 2001 down to about -- again, I don't remember the numbers. But basically, this, this additional requirement is not to meet California needs; it's to meet this growth and this growth. Not California. So basically, California.

So what's important is if this capacity get built, and, secondly, that the CD4 requirements dispute on the El Paso system gets finalized as soon as possible. Because what happens is basically, nobody's going to sign up for new capacity on El Paso system, which is, you know, the big, got the most pipe in the ground at the moment, until that's taken care of. Because the guys in California aren't going to sign up for more capacity if they have to do it based upon capacity demand contracts, because potentially, the full requirements people are going to take it away from them.

The full requirements people aren't going to sign up for more capacity, because they feel they don't need to because they're already full requirement. So therefore, we're in a stalemate until that's taken care of.

So that, to me, is something that really needs to be taken care of, and before El Paso is going to move other than what it's doing already on its All American conversion. And, hopefully, that will be resolved earlier this year, in the spring, I think FERC is saying that they're going to try to resolve this one, in March timeframe, or mid-March timeframe.

Okay. Eric, anything else?

MR. EISENMAN: And the same thing with the current expansion that's, is that going to, you mentioned going to Arizona and --

MR. WOOD: Okay. Kern is -- a lot of this Kern expansion is here. And there's also some of it down here in the lower San Joaquin, the new power plants that are going in there. There is, actually some of that gas is going into PG&E system, and Wheeler Ridge and Adelanto do run, move a lot of gas, too. They both move gas.

MR. EISENMAN: So you're assuming no expansion of Line 300?

MR. WOOD: Well, the Line 300 does do some expansion. The model does have it expand. I don't remember how much it was. But there is some expansion on it, but it's basically, if there is any there, it's to move Kern River gas up, not San Juan gas, or Southwest gas.

SPEAKER: Can I try and provide a further response to Eric's question, and give Kern River's perspective on the future expansion.

The current one is well underway, it'll be in service, 900 million a day, May 1st. But it does do a couple of things. We don't see that all of the gas that has historically moved on El Paso's southern system to Ehrenberg is going to get there. It will be diverted to the Phoenix/Palo Verde market. We see 8200 megawatts there as either under construction or recently placed in service, and the 2000 or so megawatts on North Baja. Both of those demands are served exclusively by El Paso's southern system.

MR. WOOD: He's talking this area, and over here.

MR. MORGAN: Even if those plants only operate at about a 60 percent capacity factor, that's a billion cubic feet a day of gas that has historically served southern California, that won't make it. And that is one of the key markets for Kern River's expansion. Kern River will also serve directly 7000 megawatts of power plants that are either recently placed in service or are well under construction. Beyond that, it will serve a number of existing demands in the L.A. Basin behind SoCal citygate.

But as far as expanding in the future, Kern River today serves exactly zero of the core load of either SoCalGas or PG&E. We serve non-core load only. And as those contracts on El Paso or TW or other ones expire, we think it makes an enormous amount of sense to diversify the supply portfolio of the utilities, and source gas out of the Rocky Mountains.

The Rocky Mountains is an important story. It is surging. There's, it's created, the additional production in the Rocky Mountains has created a disconnect between the supply area and market area. Today, that disconnect is $1.85, compared to our transportation rate of 39 cents.

So it's clear that new capacity is needed now, and production in the Rockies may still continue to outstrip take-away capacity. The forward price curves on the Kern River, the difference between there and the SoCal border, even after its expansion goes in service, is about 87 cents yesterday, and has been as high as a dollar. That tells us that it may not be a big enough expansion, and that there's still opportunities to expand.

Kern River can expand very economically by closing about 55 miles of pipeline that won't be looped. And we expect that in order to serve PG&E, which was the original question, it makes a lot more sense to create more of a hub in the Wheeler Ridge area. In fact, create a Wheeler path similar, there's a Baja path, there's a Redwood path, there's a Silverado path, but if you're going to expand a portion of Line 300, it ought to be just from the Wheeler Ridge point. It would be much less expensive, and it would save probably 250 miles of looping and compression, and it would also provide supply diversity to a supply basin that is really surging in production and is attractively priced.

MR. WOOD: Okay. Dale, did you have your hand up? I saw a hand.

MR. NESBITT: No, Mark had --

MR. WOOD: Oh, Mark. Okay.

MR. MELDGIN: Yeah. I had a question about David's electric work, so maybe I'm asking the wrong guy. But is it fair to assume that a lot of that gas was going to those power plants near Phoenix? And is that producing power that flows up through a standard Path 13 into northern California?

MR. WOOD: Could very well be.

MR. MELDGIN: And then the second is, we monitor what El Paso schedules every day from the scheduled volumes. And yes, we can tell the actual flow in 2002 from Permian to Ehrenberg is way, way low compared to that which you have there for El Paso Southern.

MR. WOOD: It's lower than that?

MR. MELDGIN: Yeah. We get about ten percent of what you show there.

MR. WOOD: I wouldn't doubt it. But, see, I did a real quick and dirty analysis -- again, actually I didn't, Ty did. He did this for me yesterday. And our, this Southwest deliveries, in other words, this line and this line, for 2000, it looks like operated about to 61 percent of capacity, delivery -- or, receiving capacity into California. Our data indicates about 2600 million cubic feet per day flowed into California from the Southwest, in comparison to a capacity about 4300 million cubic feet.

So, really, really under-utilized in this area. Demand has really been down in southern California. And, of course, PG&E basically only takes enough gas, normally, to meet their lower San Joaquin requirements. The rest of it's coming down off of GTN from Canada, to meet their heavy requirements in northern California, particularly in the Bay Area and Monterey area.

Anymore?

Yeah. Again, Jairam reminded me, this is projected, that we forecasted earlier in the year, and it's not actual. All of these blue numbers represent potentials, but I've actually gone through, I don't actually know what these numbers are, but I have the Malin and the Kern River number that I kind of guesstimated by summing up postings of supply on a daily basis, and then divided by 365.

Any other questions? Yes, Peta.

SPEAKER: PG&E, as you said, they need to expand their receiving capacity; right?

MR. WOOD: Yes.

SPEAKER: All but the intrastate pipelines. Do you think, how much do they expand the intrastate pipelines?

MR. WOOD: I'll have to look and see. I don't remember exactly what the numbers were.

But it's probably four or 500 million a day, I would guess, somewhere in that area. And there's a lot of different ways they can do that, as I indicated. Any, actually, combinations, what they have already added, yes.

DR. GOPAL: When you say intrastate, you mean the main lines, right? The PG&E main lines.

SPEAKER: Right, the main lines.

MR. WOOD: Okay. Any others? Kirk.

MR. MORGAN: Yeah. I would, you

mentioned a couple other projects. One was the Ruby project, and I'd just like to share our observation on both that and Desert Crossings.

It's extremely difficult to build a greenfield project. You have to amass this huge aggregation of market to meet the economies of scale. The financial crisis that we're in now makes all of the pipeline companies, all the energy companies have a increasingly difficult access to capital. And that, the Ruby project's extraordinarily expensive. I don't think it will end up being built, and that's what I would share with you.

The same with Desert Crossing. It's a hub storage project that's on the wrong side of pipeline constraints for California. It might have some value to provide swing supplies or picking resources from Phoenix, but when the California demand is meeting the storage, those take-away pipes, SoCalGas' pipes, out of Topock and Ehrenberg, are running at the pin anyway. There's no room to take in more gas there, so storage on the other side of the constraint is really of no value to California.

DR. GOPAL: Who knows anything about red

link storage?

MR. MORGAN: Red link is the same as a crossing. They're right next door.

SPEAKER: Yeah, it's in the same place. They're using the same -- well, there's, I didn't realize that there were a number of salt domes in that area until they started making these proposals, so they are using salt domes that are located, in east of California, along, generally speaking, right about in there.

Okay. Yes.

SPEAKER: Bill. Well, I've heard about Red Lake. Is SoCal going to sell it?

MR. WOOD: SoCal is going to sell Red Lake?

SPEAKER: Yeah, it's basically for sale.

MR. WOOD: Okay.

MS. ELDER: One potential buyer that's rumored, of course, is that's going to put out a message on the street that they've got lots more money to spend, like in the B's, not in the M's. They had said that they would build collateral from Red Lake south to the El Paso Transwestern. But it seems it's going to be helping that it's built to them, to get that northern connection to

Kern River.

The other thing I'll add for you, a little bit of intelligence we've heard about this and the Pacific, Texas Pacific project. We've talked to some --

MR. WOOD: Can you come use the microphone so everybody can hear you? This is Katie Elder, from Navigant. You're still -- there we go.

MS. ELDER: I'm still at Navigant. I was just trying to drill off for Bill some just market intelligence kinds of things that we've heard. I don't know if I need to repeat what I said with respect to Red Lake, so now, and Aquila. But with respect to Pashasha, we've been talking with some east of California kinds of clients and customers, and there's some concern by those folks that the El Paso Southern system is not in great shape. And that one of the reasons that you see the All American line being converted from oil service to gas service is to shore up that El Paso Southern line.

And so to the extent that you've got concerns about whether El Paso can physically deliver on that system, combined with folks who are looking at the capacity allocation word from FERC and converting their full requirements demand over to contract demands, those kinds of folks have sort of taken a pretty strong look at Pashasha. Whereas all else equal would tell you Permian gas is not going to flow to California.

MR. WOOD: Okay. Thank you.

DR. GOPAL: Katie, the information Pashasha, is that still in the press release format, or have they done any filing yet?

MS. ELDER: I just saw -- there was a notice this week that they were about to come out with another one that would be able to. So I think you'll see more of them.

MR. WOOD: Any other questions? Kirk, you have a --

MR. MORGAN: Yeah, just another observation. Maybe it's the same one. You know, we've got 900 million a day worth of shippers, and for the last six months we've been trying to keep them creditworthy, and it's dang tough to do that. Any one of these new projects is going to face the same hurdle. There are not very many creditworthy counterparties out there. And for any project to go forward in the near term, I will be surprised, because there is such a crunch on, perhaps not AIG, and perhaps not Kern, for that matter, but most of the other counterparties that have to underwrite those investments. And certainly the rating agencies are very keen on making sure, before they loan companies money, that projects are going to be successful.

MR. WOOD: If there isn't anymore questions, then I guess I'm going to turn it over to Chris.

DR. GOPAL: Before Chris begins, I have a couple of questions that I would like folks to take note of so that you can provide it.

Bill talked about the 20 percent slack capacity sufficiency earlier on, which was talked about ten years ago. So the question now is, given today's marketplace, is 20 percent still an appropriate number, or is some other number better in terms of your perspective.

And also, if we have increased storage facilities, does that change the expectation of the 20 percent slack capacity, do we need more or less. I would like you to address that, also, in your responses.

A couple of other updates. Tuscarura,

Bill mentioned, barely 65 million cubic feet per day of expansion is already online. They started in mid-December of last year. The other 35 or so, their expectation was to go to 96 million a day, the rest of it will be cancelled because there was no shipper taking gas for it.

And the other one, on LNG. The things that I have read, I don't know how many of you are aware of it, Shell apparently backed out of the Shell Bechtel partnership, so Bechtel is looking for an alternate partner.

All American, I believe was in service the end of December of last year, so it should be on service right now, right up to the California border. And like someone else, I think Eric made a comment on that. What's going to happen to the lateral. It's supposed to be in service by end of this year. We'll have to wait and see how the market takes place.

With that, I will call Chris. Chris Price will address the storage in California, and we will get some discussions going on how do we relate storage with our analysis and its impact on price supply, and other details.

MR. PRICE: Well, thank you very much.

Jairam asked me to spend just a couple of moments to talk about storage in California. And I think that it's been laid, the groundwork has been laid where we talked about the demand in California is very temperature sensitive. Whether it's cold or whether it's hot, that impacts the amount of gas demand we see within California.

One of the major effects is on the electrical side, where temperature does impact electrical generation, but besides the temperature we also talk about the amount of hydro generation that's going to be available, all within California and the Pacific Northwest. Who are the primary sources of the hydro generation that we use. When we look at the economic swings within California, we can also see how our gas usage goes up and down within the state.

All of these factors contribute to California being -- I'm not going to use the word less than desirable, because as people can point out, we are in some very nice supply bases to feed California. But we're sort of less desirable inasmuch as we are at the end of the pipeline. The straw, anything that happens upstream impacts us, whether it be the American supply/demand balance, or North American supply and demand balance, or us being impacted by what happens above us by gas being taken away from California during critical peak demands.

Storage has a major factor in moderating the impact of upstream instances, occurrences that could impact us. One of the important things about storage is that storage usually is going to be filled in periods of time when there is under-utilization on the pipe. Or there's low prices. Combination of both in the supply basins. And that's when storage is usually being filled.

At the same token, storage is normally withdrawn when we're seeing price peaks, but we see the prices in the market area, in our case, go up. Storage is in place, it's in the market. Now, that's a key word. It's in the market, it's real gas. And as Jairam mentioned earlier, when you talk about storage, storage -- or Bill, in the infrastructure, he was talking about long-term. Storage is really a long-term, I won't use the word solution, but a contributor to a solution, and it's very much used in the short-term by people that use gas or people that sell gas.

I'll try this again. There we go.

This gives you a feel for how storage is throughout the United States, or North America. And it basically says that 87 percent of the storage in North America is regulated by, whether it be the federal, FERC, or state.

In California, we're sort of lucky in that -- I should use the word lucky, in the sense that we have four primary storage operators. Three, all four are regulated by the State Public Utilities Commission. The storage operators, as you can see, SoCal is the lone operator in the southern California system. In northern California, you have three storage operators; PG&E, Wild Goose, and Lodi.

And I think that one of the important things to take a look at is if you look down at the amount of maximum withdrawal that we see today, about five Bcf. That's a maximum withdrawal. That's real gas in the market. And I keep coming back and saying real gas in the market, because anybody that's done day-to-day operations understands that what gas is nominated doesn't necessarily flow and end up at the receipt points, whether it be Malin or the southern system or the northern system.

Our gas in California is what we call marketplace storage. And one of the things it does is it optimizes transportation from the supply area. In the process of doing that, it usually reduces peak capacity having to be contracted for, and I think everybody here is familiar, if you're not familiar on interstate pipelines you play a reservation charge, whether you flow gas or don't flow the gas.

So this, by having storage when you're not utilizing all that gas, you usually can put it into storage. So you're going to transport and get your unit cost lower. It improves efficiency of storage usage.

Let's just drop down to the next one, which I think is sort of important. It's supply, it's an insurance policy, as well. It provides insurance, supply reliability, and price stability during demand peaks.

The fact of the matter is, is when the demand peaks happen, the fellow, the end user that has the storage, or the marketer who has storage, puts gas into the marketplace right there. What's that do? It doesn't necessarily lower the price. In fact, you'll probably see the price continue to be high on demand peak, but it moderates that price increase.

Finally, I think the others we get down to, provides an operational tool for balancing supply and demand. Both within SoCal and in northern California, there can be penalties if you don't meet your supply with your demand. And storage allows you to do that.

One of the tools, and the next was, I call it a value pyramid. It's a, you know, a simplistic mind here. I saw the food pyramid and I said why don't we talk about a storage pyramid, because each company puts a different value. Each company puts a different value on different things. Operation reliability may be exceptionally important, for example, in Las Vegas, that's not California, but it's someone that has to have gas every day.

Or a sugar factory, that'd be a good example, because if the sugar factory loses its gas in two or three days, doesn't have steam, you might as well take all the equipment, load it up, and sell it as scrap. That's what happens. The sugar crystallizes, and you're stuck. So it has different values for different usage.

One of the, there's a couple of things, when you get down to, I talk about inter-month arbitrage, inter-month arbitrage, intra-month arbitrage, we're talking about parking and lending. And every one of these storage operators, whether it be SoCal, Lodi, PG&E, Wild Goose, they all do parks and lends. And what's do? Parks and lends, I'm a user or I'm a shipper of gas on the pipeline system, I don't have a market, can I give you the gas, and I'd like to take it back in August. They'll determine a value to do that.

Or I need gas today, and I don't have the gas on the system. I'm going to borrow gas. Usually they're using some financial tools, but they're going to take it back in a different month or a different season, it gives them an economic advantage.

This is a very, very simplistic, and I mean simplistic, because the solution to this problem is, there's a multitude of solutions that you can use. But this happened to show how you can, how pipeline -- this happened to be a fictional power plant. Peak demand was 150,000 a day. Low demand was 50,000 a day. Average market was 100,000 a day. Instead of taking out pipeline capacity in this scenario, for 150,000 a day, he takes out pipeline capacity of 100,000 a day, buys storage to have them put in 50,000 a day, or take out 50,000 a day, and what it did is it just shows within that scenario, because his load factor was 67 percent, his effective cost of transportation if he took out 150,000, became $1.20 a decatherm. With storage, counting the cost of storage, it turned out to be about 95 cents.

Now, this is simplistic, because in reality, he may have a multitude of things he'll do to moderate his cost. He still might take only 125,000 or 100,000, or 75,000 and buy daily, sell daily. Depends on the activity.

The final slide that I wanted to show, and I'm trying to figure out how this fits into the workshop, but I think it fits in this way. What it tries to show is the cycle ability, the higher the cycle the storage. Now, a cycle of storage is if you have a Bcf of working gas and you churn that 12 times in a year, you have a 12-cycle operation. Okay. The higher the cycle, the higher the cost.

The less sophisticated, what the chart

shows, is the cost going up, and it shows three different blue lines that show the different type of people that use storage. The bottom line is a less sophisticated person, or company. And you see the greatest value they get is around two cycle, two and a half cycle. The more sophisticated is another line. And it shows that they can use that system, use it and probably get away with four and a half to five and half, maybe six.

And then you see the greatest value is the, the top line is a very sophisticated operator of storage. He's using hedges, he's using all kinds of things to make sure that he gets his value. And really, that comes out his biggest value is going to be around six.

Now, EnCana, they get these numbers because they do an awful lot of storage up in Canada and they see how people use storage. In fact, a storage operator likes to have someone take very high cyclic service because they know they're not going to use it all.

So, again, storage, I think as you get in your discussion, storage is a long-term, not solution, but part of a solution, the pipeline capacity coming into the state. But it also provides some very, very important things in the short-term. And as you look through your workshop here, and we go through the workshop and we start looking at storage, it complements both short-term and long-term.

And another way to look at storage when it's -- start to use it with pipeline transportation, it's like a shock absorber on a car. It can levelize that car. And remember, the more pipeline utilization you get, the lower the unit cost of gas. The lower the unit cost of gas either develops a profit to a marketer, or savings to a user.

And that's about all I have there.

Yes, sir.

MR. BRATHWAITE: Could you elaborate on that statement you make about short, storage being a long-term, a contributor to a long-term solution, even though it's primarily used in a short-term environment?

MR. PRICE: Well, in that sense, Leon, what it does is when you start looking at sizes of pipe, interstate pipelines, and you find that -- you take a look at our interstate pipelines and El

Paso's running at 61 percent, I don't know what Kern is, it's a fairly high utilization pipeline, Kern is, you can see as you start to go through the process of sizing your interstate pipeline, people would have the availability of storage. And again, this is storage, whether it be -- whomever's providing the storage.

What it allows you to do is look at those periods to size the pipe to meet the demand, because you have storage on system, you can buy storage, put the gas in, and then take it out when it's needed. And that's where it helps you to have more efficient interstate pipelines.

I don't think it's, I mean, one of the discussions, I don't know Kirk -- I don't know Kirk, but it sounds like he's with Kern River Pipeline. In one of those discussions that's going on today. Now, the expansion on Kern River, where are the people going to have the shock absorber during peak and slack times on that pipeline. And the questions are being asked by their customers, where's the storage. Or where can we get storage, on Kern River.

That's, that's what their customers are asking. And that, you know, they've subscribed for a great amount of transportation. They want to utilize it because, again, the greater the utilization, their unit cost is what they expect it to be.

And so they're looking for how can we have storage. Now, whether or not they can make an arrangement with SoCal to do some storage in SoCal, or with PG&E into the PG&E service territory, we're all trying to figure that one out. But that gives you an example in sizing. That's how long-term it can work.

MR. BRATHWAITE: Thank you.

MR. PRICE: Yes, sir.

SPEAKER: It seems like there's some sort of trade-off between the cost of pipeline capacity, building excess capacity and building storage. Is there some kind of rule of thumb around somewhere that tells you whether it's cheaper to build more pipe or cheaper to build more storage? Or you just have to work that one out?

MR. PRICE: That's one that you sort of continuously sit down and you, you have to, you almost look at it individually, with customers. I mean, they look at their demand, and then if they have storage available. What happens is, is in, you know, you get these areas like in the Northwest, where -- Northwest Pipeline, and I don't know its recent history, but it's very much a winter pipeline. Their utilization in the summer is very low. People want to put in storage.

Bill.

MR. WOOD: You mentioned basically the storage facility that might be able to serve Kern River, which kind of implies, then, a storage facility potentially in the lower San Joaquin Valley. At one time there were several proposals in that area. Is your company still looking in that, or is it, what's your feeling bout developing something down there?

MR. PRICE: Well, EnCana's philosophy on storage is that unfortunately, it can't find the, every -- let me -- not rephrase it. Let me say it slower.

EnCana's philosophy on storage is, unfortunately, you can't just put a storage facility where you'd like it to be. And their philosophy is they look for the location, not the location, they look for the field that they can do the storage and get bang for their buck. Not so much on an economic sense of where it's located, but being a good storage field. So consequently, when they look to San Joaquin there hasn't been anything built down there. I don't think they're looking at anything down in the San Joaquin Valley.

SPEAKER: You alluded to it briefly a couple of times, but could you elaborate a little bit your thoughts on the rapid development of the markets in natural gas since deregulation, and the role of private storage and strategic storage? That's a very general question, but --

MR. PRICE: Say it again. Can I comment on the --

SPEAKER: Relationship between the rapid development of, of financial markets in natural gas since deregulation, say over the past 10 or 15 years, whatever, and the role of private storage or strategic storage, other than the standard operational storage for utilities. I mean, you talked about hedging, you talked about --

MR. PRICE: That's really a good question. And not only -- he's wondering, I think -- did everybody hear the question? Is the development of, development of storage and how storage is used sort of goes in, in the question, does it go sort of in hand in hand with the hedging and the financial tools that people use today. And the answer is yes.

Some people say that they don't need storage, all they need is the financial tools, the hedging, to firm up gas. And that's why I kept -- go ahead and answer that. Do you want to answer? No. Because I'm going slow on this one.

The, my personal feeling is that it's been a development of both. The hedging has created, the financial tools have created the opportunity to do things in the longer term that we hadn't before, do them more by the seat of the pants, rather than the seat of the pants that we used to quote gas prices, I'll give you a yearly gas price, we had no idea what the gas price was going to be. It has allowed producers, certainly producers look and do hedge some of their production.

Going back to the morning, this morning's session, they look at long-term trends and they'll look at the, they look at the long-term price forecast, is where they look. That's where they put their money. That's a producer.

When you deal with the financial markets you're dealing on a daily basis, and those guys are just managing deltas. They're just managing deltas. They're managing what they can make today. Today they're a seller, tomorrow they're a buyer. Then they're a seller.

So I think individual storage, and I think part of it goes back to when we had 636 and some of the relationships to how the pipelines, how the commitment of the supply basins to feed the utilities. I think that's part of the situation. And I think maybe this gentleman, who's followed it longer than I have, may have an answer.

SPEAKER: Yeah, there's another one, I'm a little fuzzy. I know Eric will remember Nesbitt's maxim number one. Remember what it was? Pipe is cheap compared to gas. Everybody repeat after me, pipe is cheap compared to gas. Pipe is cheap compared to gas. Pipe is cheap compared to gas.

If you're going to over-build something, over-build the pipeline system. Look at the -- and if you need an analogy of that, go look at oil pipe. Oil pipes are virtually free, cost you nothing. And people don't store oil that much. I think the reason store natural gas, one of the main reasons, is that people who are producing it, producing associated dissolved gas, want to produce it. Not much associated dissolved gas anymore.

People want to physical arbitrage. It's really important, you can push that down, I mean, Carl knows this. Wire's cheap compared to generation, too. Until you take it over under the rotunda there, and then they don't like those little gray wires very much, and they figure a thousand reasons not to build them.

But you've just got to keep in the back of your mind that as big a deal as we all make the pipe, pipe is cheap. And to weld another six-inch diameter on your pipe doesn't cost you anything. Storage fields are expensive and they're hard to operate. They're necessary. They're necessary because people want them,they want to play physical arbitrage games, they want to play price breaks, and that's like playing the stock market.

MR. PRICE: Well, the one thing that storage does operate, and I keep, marketplace storage operates, and it's really important to understand. It's real gas. You can't count on the gas on the pipeline. I mean, yes, you can count on it, but in the times when it's, when everything's coming down around you, you have problems.

MR. NESBITT: Let's go back one second, too, because, you know, I would contend that an NLM 6000 is the storage price, in the same sense that gas storage is storage. And your choice is you either want to engage in demand elasticity effects you want to ration gas demand out there to guys who don't want to pay for it, or you want to have this regulatory scheme that we've lived in for god knows how many years, where it's everybody's god-given right to get an MWA and get an Mcf and, you know, we saw those pictures in the seventies where somebody's toilet was frozen in Minneapolis, and, oh, my god, it was the most horrible thing.

There's other ways to deal with this besides paying tons and tons and tons and tons and tons of dollars for insurance. It's really important to keep the cheapest insurance you can buy.

SPEAKER: Just a follow-up question on that. Because that's not really my question. I know storage is expensive. But relative to, say, ten years ago, it seems to me, and I haven't studied this, but you see natural gas financial markets are the most developed of any energy commodity, and it seems to have promoted more of a demand for storage. You know, we see private storage popping up in California and Texas. And, again, I'm not real sure about this except anecdotally, so that's why I'm asking the experts if they can confirm that observation.

MR. NESBITT: There's another theory of storage, which I subscribe to. Look at the storage that was built in the past. All that was built because of the asymmetrical reward and penalty structure that the LDCs had. You know, you run short of gas, you end up in court. So what do you do? You store like hell.

Now, Dale Nesbitt's not stupid. You paid me to store it, paid me to be, have excess energy stored. Dale Nesbitt will figure out a way to do that.

SPEAKER: Well, that's why I'm talking about the prime storage which isn't regulated.

MR. NESBITT: Well, so what happened was we allowed private entities to lease storage, so they bought basically a swap against storage. And then they started playing the price arbitrage game, and we saw a fairly rapid increase in the utilization of storage when that happened.

I would argue that it's a fundamental change in the reward and penalty structure for storage. That's why these guys are out here. They're out here because they have a reward/penalty structure that they're able to offer to their customers who want to play. I think, you know, in the good old days, storage was a poorly utilized asset. Look at Columbia Gas distribution, for example, which covers five states. In March, it'd be half full.

Where I grew up, that wasn't very smart, yet their reward and penalty structure said that was the smartest thing in the world.

MR. PRICE: When you look at pipeline construction, the one thing to bear in mind is that it goes back to what Kirk, pipelines, although you'd love to have lots of pipeline capacity, under-utilization, someone's paying for that. And in most cases, when they're paying for that, they're going to pay more for the under-utilization, it's going to cost more in under-utilization than it will be for them to use some type of storage.

So there is a balance there. And that's one of the things here.

MR. MORGAN: I would actually agree with Chris. Coming from a pipeliner, that doesn't sound right, but what we see in our pipeline, most of the power generators, and that's what storage is used for now, Kern never needed storage before. SoCal's system is ten percent monthly balancing its free storage on SoCal. Essentially free storage. You don't have to come within ten percent on a month in an account.

Kern's original market area was thermal enhanced oil recovery. That's similar to the sugar beet thing. You don't let it cool off, ever. And it's 24 hours a day, seven days a week, uniform hourly take, Kern didn't need storage. We have a lot of electrical generation being connected to Kern; it does need storage. And we're working on making storage available either off system or on system for our customers. But they certainly will need to manage the swings that are inherent in power generation. That's a 16 hour day, or a 12 hour day, and they want to burn all the gas all on peak at one time. Storage helps them do that.

If the question is when do you invest, we're not willing to invest in wells and cushion gas, and compression if there's a market efficiency answer. And SoCalGas has got a lot of storage. They've got 119 Bcf of storage. It may not cycle as frequently, it may be a more traditional storage than a seasonal storage, and what is in vogue now is more high deliverability, high injection, high withdrawal, multi-turn services, and I frankly think California needs some of that.

But again, in the last couple of years the most expensive thing on a storage project is filling the base gas. You don't get out everything you put in, you know. About half of the gas you put in is there for, for good. And when gas prices were blowing out to $10, nobody could build an economic storage project. I was shocked that Lodi went forward, frankly, with those pricing scenarios.

Today, we're back in a who's willing to

pay for it. Is there a creditworthy counter party, and that's probably what inhibits new storage projects today. But when the right market signals are there, Kern River is definitely interested in developing on system storage, as long as it's competitive with what the existing storage providers can do.

DR. GOPAL: Take two more comments, one from there, and then we'll come back here.

SPEAKER: I just wanted to agree with Kirk here. I think one of the things that's fundamentally changed is that we now have a lot of power generation. That burden is being pushed back on the gas infrastructure.

Secondly, I would observe that Sempra's project, project, and Shell's project all have gas storage, so to speak, which will have an impact on the site. I don't think a lot of people realize that. And that is tied to it so that's another benefit of LNG that not everybody has considered.

SPEAKER: I'm back here. The last diagram on that. The customers you have there, you suggest that some are less sophisticated than others. How many do you think are in the various category, and then what would happen if all became sophisticated?

(Laughter.)

MR. PRICE: Well, if they all became sophisticated, what the slide tried to show is that even if they all became sophisticated, they'd probably get their best value on a five to six cycle service. We see people that pay and do have 14, 15 cycle service, and the reason they do is they, they're buying it for insurance. It's an insurance premium. They have a real need, they have to have gas.

SPEAKER: Do you think there's some people that ought to be -- you know their business a bit, and they seem like they're just not very sensible about what they're doing, and how many -- I work for an academic institution, so that's my definition, that's --

(Laughter.)

SPEAKER: Part of it is better education.

MR. PRICE: I think it's, part of it's better education. It's also what their purpose is for. I mean, when I say what their purpose, if they've having, let's say, for example, an end user takes storage out and has a marketer manage it for him, he'll usually make an arrangement with the marketer to take some profit that he can generate by cycling and moving this storage. He doesn't want to hire a daily buyer, he doesn't want to do the financial arrangements that allow him to do different types of arbitrage. And that would be a, he's just not going to do that.

As you get more sophisticated in the chain, and, you know, the one at the top would probably be a very, a very sophisticated trading organization that took out storage to make money, yeah. And, you know, there's a lot of traders that do make money, but just being a trader today isn't the thing to be, you know. A lot of companies (inaudible).

Thank you.

DR. GOPAL: All right. We will take up anymore questions later on, after the next session. The next session is going to be, will be when you pay 25 to 50 bucks for one Mcf of gas in one year, and right the next year you pay just two bucks, there's something not right. And what we are trying to get at by that is, you know, what is the reliability in gas service, where is the reasonableness in the price, and what sort of risks are we taking in addressing these issues.

Bob Logan will lead this issue. This is a fairly new issue in terms of the attention that we are giving it, compared to maybe in the past, plainly because of the crisis that we have seen for the last few years. So, Bob.

MR. LOGAN: Thanks, Jairam.

I hope that all of you picked up a copy of the handout, the report by Bob Weatherwax on the integrated risk methodology.

I'm going to start by giving you a little bit of background. Back last October, we issued this report, the Natural Gas Infrastructure Issues, and in that report Commissioner Moore, who's moved on, wrote a foreward, a preface. And in there, he talks about how the Energy Commission encourages all participants in the California natural gas market to participate in the re-evaluation of the current design criteria for natural gas infrastructure, and apply risk analysis to develop design criteria better suited to the new paradigm.

Well, we at the staff obviously listen to our Commissioners, and went about trying to figure out what a risk analysis is. Since we hadn't done a risk analysis in quite a long time, we went out and tried to find a consulting firm that knew something about energy and knew something about risk, and we found Sierra Energy and Risk Assessment. And right here, to my right, is Bob Weatherwax, the author, and hopefully he'll be able to answer some of your questions, if you have any.

Bob used to work here, and, in fact, during the days of the Point Concepcion proposal, he performed a risk analysis. And if you have a copy of the report and you're looking at the Figure 1, I believe it is -- yes, Figure 1, this is actually from the Point Concepcion hearings. This figure was put together by Bob when he was here at the Commission. And basically, what this shows is the probability of different forecasts based upon weather patterns.

I think that the key to Bob's report is contained right in the very first sentence. And the key word is "probabilistic". The key to understanding what we're trying to achieve with the risk assessment is understanding that we're trying to mathematically achieve some kind of probabilities. We all know that weather patterns repeat themselves, there have been droughts since biblical times, we know this from geology, we know it from the rings in the redwood trees.

So we know, standing here today, that there will be another drought. As Dale pointed out, we have no idea what year it'll be. We don't know exactly what month and year it'll start, but we know there'll be more droughts. And we know that the droughts will vary in intensity and they'll vary in length.

One of the things we are able to do is utilize the extensive weather data that's been collected in the United States by, currently NOAA is the warehouse where they keep the data, and we can start establishing risk probabilities. What are the odds that there'll be a drought and how extensive the drought will be. The other area that we can do the same kind of analysis is in heating degree days and cooling degree days.

One of the things that we are going to do with the weather data is we're going to move away from our California centric view of the world. When the Energy Commission started out in 1976, the borders of California were the borders of our analysis. The rest of the west wasn't that large, their needs weren't that great, and they didn't really impact what was going on inside of California. And as many of you know, at that time we had the ability to switch back and forth between oil and gas. In fact, we didn't use that much gas in our power plants, we used mostly oil.

So now, the world's different, as you also know. We're the ones at the end of the straw, we're the ones that have to see what everyone upstream is taking out of the pipes before they get to us. So both from an electrical point of view, electrical demands upstream and gas demands upstream are affected by weather conditions. So we're going to be basing our analysis not just on California weather patterns, but on patterns for the entire Western Coordinating Council.

Other aspects of the risk assessment that we're providing is although this started out as a natural gas topic, or natural gas area, one of the things that Bob Weatherwax, when he put his report together, somewhat educated us to, is that we cannot do this in the gas unit. Either this will be done Energy Commission-wide, or we will fail. It's going to have to be a joint effort of our demand group, our electricity analysis office -- you saw David Vidaver earlier today from that group -- and the gas unit.  And we're also going to be partnering up with our colleagues at the California Public Utilities Commission, and you. I mean, either we're going to be able to get some feedback from you, the public and the stakeholders and your interests, or we're not going to be doing very productive and relevant work in this area.

But basically, we're going to be expanding our view so that we're going to be looking at non-EG demand, res, commercial, industrial, for all the west, and that'll be coming out of our demand capabilities.  We'll be doing our EG demand, that's David Vidaver's group, in which we'll be modeling the entire west, and the electricity demand in those area.

Then the gas unit, using the NARG model, is going to be responsible for pipeline flows. And we're going to be trying to determine these across various hydro conditions and heating degree and cooling degree bases.

The purpose of doing this, at this point, as we see it, is to evaluate alternatives on a portfolio basis.  We tend to agree, in the gas unit, with Dale, that pipe's cheap and a good way to solve all problems. But, as was mentioned before, we have a law in California now that 20 percent of the new purchases should be coming from renewables, and we fully support that goal. There's also regulatory changes that we support. Many of you might be familiar with our real-time pricing efforts, and basically, the concept of trying to cut out that demand that comes about due to droughts and temperature changes. So that instead of installing infrastructure and hardware, we can try to get demand to be more responsive to these changes.

Other purposes that we're trying to achieve with this risk approach is to get some insights into market behavior. And you may have noticed that in the questions that we sent out, one of them asked how is the market going to handle the demands of the kinds of weather conditions we saw in 2000 and 2001. Are there market incentives to encourage developers to put in enough pipe to deliver enough gas to meet the kinds of demand surges we see when the weather changes.

And here we come to the commercial, or

the advertisement. One of the reasons I'm presenting this is to get your interest up, hopefully, and encourage you to come back for a risk workshop that you're going to all receive e-mail notices of, that the Energy Commission is scheduling within the next couple of months, where we're going to be talking about what kind of risk assessment the Energy Commission should be doing, what kind of topics we should cover, and basically get your input.

I know we didn't cover this in our paper that we distributed, but you do have Bob Weatherwax's report, and if you have any questions, Bob and I are glad to answer them.

Well, I don't see -- oh, there we go.

MR. MELDGIN: Yeah. We have several questions, there's like four paragraphs there. I realize a lot of people perhaps didn't have much time to review this. And you didn't mention it just now, but the report has in it a notion of weather vintages. And as I understand it, the idea is let's imagine the population infrastructure, and so on, is going to be in place in, say, the year 2010. And then let's say okay, given that infrastructure of population and so on, what would the demand be and what would the hydroelectric supply be, under weather conditions in, say, 1975, where you exactly replicate year 2010. Do the same for 1976, 1977, et cetera, then you have 25 years, and you can make some intelligent judgment about what's the probability of weather causing -- do I have that right?

MR. LOGAN: Right. And if I can just expand on that. The concept is to use, to start using 25 actual historical years. There are a couple of reasons for that. One, we didn't want to take the driest year coupled with the hottest summer, coupled with the coldest winter, since that's never happened. We wanted to take years that actually happened, whatever the heating degree days and cooling degree days with the hydro conditions for that year. So that we have a true historical year that we know, that we can put into a probability curve across the 25.

Now, as we go forward, we'll keep adding years, so that we're going to build a database of the 25 and then add actual experience as we go forward and build it up to, hopefully, 50, 100 years, whatever, as we go forward. But the benefits of that is we're able to get the probability, because we can look at how many times the hydro generation exceeded a certain level in each of those 25 years and get probabilities, and the same with heating degree days and cooling degree days.

We're also able to get sequences. In other words, what are the probabilities that if you have a dry year it'll be followed by a dry year, or a succession of dry years. And what are the probabilities if you have wet years, that they'll be followed by wet years. And so we'll be able to both figure out our probabilities by using the actual history, and also sequences, probabilities of sequences.

SPEAKER: There was one more recent one, '75 was a good starting year, that was an understanding as to the availability of a higher quality of, actually hydro data from the PG&E system. So that was kind of a, after '74, was when that became clear and it hadn't done anything for the hydro divestiture.

MR. LOGAN: The EIR is available. I mean, it's a completed document.

SPEAKER: Well, yeah, the document is availible.

MR. LOGAN: Right.

SPEAKER: But divestiture certainly was.

MR. MELDGIN: Well, now I'm going to get into an earlier key modeling point, and I'll try to be quick.

It does seem to me that the -- and Dale's here.

MR. NESBITT: I'm writing. I'm writing.

(Laughter.)

MR. MELDGIN: The risk methodology report is somewhat limited, because it addresses the models that PG&E has -- pardon me, that the CEC is using today, and they are going to miss an interaction, I think. I think what is envisioned, and the report wasn't crystal-clear to me, but I think what's envisioned is you start with a base case set of gas prices at various hubs around the west. You put those into multi-sim. Multi-sim comes back and says given the demands in the year 2010 for electricity, and these sets of prices, electric generation around the western stream will occur so much in the northwest, so much in Arizona, so on and so forth. That will result in gas demands for the power plants.

All of that will then be put into NARG

as regional gas demands for power plants. You'll add in the regional gas demands for core, et cetera, run NARG, and NARG will say aha, there's going to be a crisis in the Pacific Northwest because there's not enough gas.

Now, I think that that will overstate the severity, because it misses an important reaction of the market. And in fact, we saw it in December of 2000. What happened was it was one of the coldest years, coldest Decembers on record in Washington and Oregon and Idaho, and the competition for gas drove the price at Stanfield, for example, way, way up, way above what it is in the Southwest. And the result is that all of a sudden, people in Arizona found it economic to burn more gas there and ship the power to the west.

That was the only month in the five or six years following this that the flow on the DC line was from south to north. I've never seen that before or since. And I don't see how that sort of interaction will be captured by first running multi-sim with a base case set of gas prices, and then putting that into NARG. So I think it's important.

Comment?

MR. WEATHERWAX: Thank you. I did get a brief chance to review your comment, and it is a good one. And I'm glad you focused on the fact that I was trying to do it as closely as I could, using models that are currently available or kind of right there, in order not to necessarily generate any more controversy than I can.

But before I get into that a little bit, let me just give you a brief history. I don't know if you guys remember, but in the late 1990, there was a situation where power was $100, and I don't know if you remember the EPA screaming at Mike Peavy, when he was president of Edison, over what they thought to be unconscionable profiteering.

So when things do get bad in the Northwest, the flows reverse, not only in the DC but on the AC, as well. And so that's what we were kind of looking for, those kinds of situations.

Now, your description of what happens does not fully take account of the two cycles that we talked about doing. The way the Energy Commission currently runs its pro-sim, or its multi-sim, depending on how you want to label it, is to assume that there's unlimited gas supply. And we propose not to change that.

And, but then, once you get through the NARG monthly model and you can identify shortages, if you should identify shortages, which I tend to expect there might be some of, you would then run pro-sim or multi-sim using the limited fuel algorithms that actually are available for the model but haven't been taken advantage of.

So you can define by pools in various areas of the western region, the amount of gas that's available. So you will, when you get to a point, start moving gas by way of wire from the Arizona/New Mexico area to the Northwest. And that's one of the situation. You will, indeed, do that. You'll see that happening, and that would be a reasonable response.

Now, it's not going to give you, though, good capturing of the total costs involved. Those are typically done, those algorithms to do the limited fuel are done with shadow prices. The shadow prices aren't reported, and so you don't have a reasonable way of kind of teasing from that the actual cost impacts that you might have.

You'll know how close you'll come to running out of gas, but you won't have a good idea as to what the cost might have been.

There is a further step you can take with these limited fuel algorithms. We used it with another model, our own model, for modeling gas supplies to the Edison units in Ventura County. Their 225 units had cheap prices for like 16 million a day, and then they had more expensive normal SoCalGas prices for the remainder. And you can do that, as well, with these limited fuels. You can make your assumptions that if you're up to 80 percent of the total capacity of a pool, fuel pool, it has one price. And then as it goes up, it could almost go asymptotically to a vastly higher price. The models are perfectly capable of doing that, and can solve what I do think is an interesting and important problem.

The question is, if there's a certain hesitancy to introduce use of limited fuel modeling at any level, you really want to take it that second step. And that's a personnel and, I think a determination based on the amount of efforts you need to devote to it.

MR. MELDGIN: So I guess what you're

saying is that it would be three steps, and I only mentioned two. You do multi-sim and then NARG, and then multi-sim again.

MR. WEATHERWAX: Right. Yeah, two cycle, yeah, two cycles for the whole system. And then you'd run NARG again to make sure that you've kind of satisfied your demands as NARG had dictated them to the pro-sim modeling.

MR. LOGAN: I'd like to follow up on that. And certainly what Bob just said is his best opinion, and that's why we hired him, because we value his opinion. But from now on, we've moved this into the stakeholder arena, and to the extent that we decide to implement what Bob has recommended, we'll be using our judgment and we'll be asking for help from the community of interested parties and stakeholders as to what the best way is. I know that many of you here are also modeling these topics, and, you know, we now have moved into that area where we want to make it a joint effort between the Energy Commission and the interested parties.

But I think one of the things that is going to happen is we're going to start using judgment, because obviously, there will be a price response. I think that's the heart of what you're saying, that you just can't take the population today, whether it's going to, say it goes up 50 percent and say the demand will be 50 percent higher just because it gets cold. Because if that shows there's no way to deliver that without a five-fold increase in price, the demand won't be there.

So that it's going to have to be judgment calls made when you actually implement Bob's advice.

Dale, do you have a point?

MR. NESBITT: Yeah, I have a couple of comments. You might not like them, but I'm going to make them anyway.

When I studied probability under Ron Howard over at Stanford, and I mention him because he's a lot smarter than I am, he asked me a question one day. He said, hey, Dale, what's the probabilistic model of ignorance? I looked at him and he said, that's ignorance, too.

Is probability is a critical issue that faces California? Who thinks risk is a critical issue that faces California today, as we sit here today?

No hands -- oh, one. Risk?

MR. MELDGIN: Okay. Risk, probability. The reason we're screwed up under the rotunda over there is because we don't understand risk. With all due respects to Mr. Moore, who's now hanging around taking a big risk, that isn't the problem with it. But in risk, there is variables in there. Who thinks weather is the number one uncertainty facing California?

Seriously, get your hands up. We can do a risk analysis of weather.

SPEAKER: Into the near time horizon.

MR. MELDGIN: Forever. I'm not speaking for your marginal density, but your conditional density.

SPEAKER: You've got three rings that are showing what we now call a drought, lasting a century in this area.

MR. MELDGIN: Big deal.

Okay. But you have to solve --

SPEAKER: So the whole, the whole civilization would have to change.

MR. MELDGIN: Well, you know, I ain't going to see too many more tree rings, and neither are you.

(Laughter.)

MR. MELDGIN: The issue --

SPEAKER: I'm not -- in the long run we're all dead. The fact is we're planning for the future, not years in the future.

MR. MELDGIN: Well, my -- here's the thing you need to do, I think, when you're looking at probability. Okay, so people agree, I think, that weather's not the number one variable, even if it is the number one variable. Any other variables you think we ought to have in our risk analysis?

Okay. Well, let's talk about some of the risks that I'm offering for your consideration, that investors think about California right now. Let's put you, you're the CEO of Duke. You're the CEO of El Paso. You're the CEO of Sempra. You're the CEO of PG&E. What are the risks that you see?

Risk of expropriation of my property. That would be one. Risks of less than market rates of return, that would be one. Risks that I can't get any siting for my facility, to know they might otherwise be economic. That might be one.

Okay. The problem when you do these

kinds of risks analysis, and you're doing, quote, unquote, naively, where you think weather is the risk, and you bring that to the policy-makers under the rotunda, they think they've solved the problem, and they haven't. It makes me real nervous to make these decision analyses and risk analyses when we do them with weather. I mean, I think that weather, I'll overstate for emphasis, weather modeling is like the hammer and the nail problem, right. If all you've got is a hammer, everything looks like a nail. If all you've got is a weather model, everything looks like a weather modeling problem.

And it isn't. I'm really cautioning you guys to go to slower stuff, and not do this stuff unless you're ready to really look at the hard risk issues. Okay.

One more issue on risk. Let me give you one more thing so you can really hate my guts. The biggest problem in risk, has any of you ever run a little simulation with a crystal ball, or at risk, you know, you put little probabilities in the little model that you have, and you run it. It gives you a little pie chart out the back, god, that feels good. Man, you've solved the hardest problem in the world, and it's perfect because you put risk in. You put probabilities in. Right?

What is the number one screw-up that you always do? Always. Always, always do. You forgot the variables correlative. You used sampling from a little sampler, and they're running through the model, it's just super. Perfect example of that, as you can guess, price and power price are probabilistically independent from what you're trying to do in risk analysis, because you're wrong. There are samples that correlate sometimes, and other times there are not.

If you haven't built yourself a serious time structural model to represent that, that hard wires your gas model with your electric model and runs them as an integrated mass, my recommendation is that -- I'll even go further. Don't use multi-sim, don't use pro-sim. You need a market model. It is not a market model. So you're not going to get market correlated risks out of it.

So when you start talking about trying to get these aleatory variables, they call them, these parameters that are probabilistically correlated, and you're trying to drive them through to a bottom line on investment, and a bottom line on price, it's a really hard problem. There's a Nobel Prize waiting for you at the end of that one. And you can make a lot of mistakes on the way that mislead the policy-makers, because they have this comfortable feeling you take care of all the risks.

Last quick one, then I'll let you have the floor. I remember back in the early eighties, there was a project that I was involved in in one of the oil companies. And they came to a bunch of oil modelers and they said run me your oil model with three uncertain variables times two settings. So it's a little tree with eight prongs on it, right? You pick the variables that you think are the most important in ascertaining oil price, and you bring them down to us and we'll set the probabilities on those.

So you use the model at the end of the little eight-prong tree and you run that model, and you get yourself a probability density function over oil price; right? Worked like a gem.

And what they did is hired a bunch of consultants to come in and assess the probability distributions over oil directly. What did they get? They got four times as high a price, and it was trash.

The models worked. Put the models together and integrate them the way that I think Mark Meldgin was alluding to. For god's sake, don't go through this modeling act where you've got probabilities out there on the side. You'll never get -- their consultants will get rich, they'll like it. But you'll never get there.

End of story. I'm sorry, I interrupted you.

SPEAKER: As Bob mentioned, we are thinking of having a, we will have a workshop, I think, in the end of April, in which we propose what we're calling a risk assessment framework. So what they were talking about today, the weather part, is just really one component of that framework.

And the question I think that you're really driving at, which I think is a good one, is what, the real question is what kind of analysis and what kind of decisions can we make at the Energy Commission that will make the energy markets work better in California. In that sense, reduce the kind of risks we've seen California consumers exposed to over the recent years.

So that's what we really mean by risk. So, and we haven't fleshed this out fully yet, so we're in the process of working this out. It certainly would incorporate some of the things you are alluding to, about how investors think about risk. We're not insensitive to that. But if you look at some of the stuff that has been said earlier today, and actually some of the causes of the 2000 problems, you see they were due to shortages in basic infrastructure. And these things seem to come in cycles.

MR. NESBITT: I don't agree with that at all. I don't agree with that at all.

SPEAKER: Okay. Well, the truth is that we don't have a complete diagnosis of the problems we had, so you talk to two people and you can get three opinions at this point. So there are so many things that went wrong, that I don't think we will have a complete diagnosis for a long time. Anyhow, that's the --

MR. BRATHWAITE: Let me ask -- hold on a second. Let me, so I could ask a simple question.

We are servants of the State of

California. Now, from the standpoint of an average Californian, do you believe that the weather risk is far greater risk to that person than, say, regulatory risk, which is a risk that Dale seemed to be hooked on right now?

SPEAKER: Well, yeah. I think, I just think that --

MR. BRATHWAITE: Did you understand my question?

SPEAKER: I just think that if you have a good comprehensive risk assessment framework, you will try to incorporate all of the risks in a coherent way, and it doesn't necessarily make much sense to try to decide what is the biggest risk. The idea is to have a reasonable approach so that you prudently manage risk, in terms of, you know, how do you make policies that are more prudent in terms of managing the risks that matter to California customers. That's the question.

Of course there's regulatory risk. There's, a big risk is the regulators will do a stupid thing and make things worse. And -- yes.

MR. NESBITT: Okay. And you've heard of diversifiable risk, and I'm sure you've read the papers and all the other papers on diversifiable risk, which said that the risk is small and that should be expected by decision-maker. I don't really, I'm not risk sensative with regard to small risks. Okay. And if weather risk is small for me, why should I pay you a dime to take care of it?

There's three, six-odd million folks in California, each of them bears five bucks with -- in risks, quote, unquote, certainty equivalent minus expected value from the literature, that's small. And I would argue that it is with regard to weather, unequivocally. Why should we manage it, why should you, as a public service, manage risk for 35 million people who can self diversify, and they can.

SPEAKER: By the way, I don't think there is any implication that the government or the Energy Commission, which is one agency of the government, is going to take charge of managing risk. I think that's, that is certainly an illusion, a false and a bad idea. That is not --

SPEAKER: What is really -- yeah, I totally agree, it's a very bad idea. It can't be done, and shouldn't even be thought of.

What is important is to try to ask the

question within the framework of these processes that we have, what can we do that may contribute in a positive way to more intelligently manage risk. You know, just take a simple example. During 2000, some people think, and we don't have to agree on whether this is true or not because it might be true, that the CPUC made a bad mistake when they inhibited the electric utilities in buying more long-term contracts when they would like to have done so.

Some of the utilities feel that way about it. And in retrospect, it's easy to see, well, wow, if they had done it, maybe we could've saved a couple of billion dollars. Collectively.

MR. NESBITT: I would agree with that, but I would say that's not a risk assessment.

SPEAKER: Okay. Well, if the PUC had a little bit, been a little bit more cognizant of sort of some basic -- I personally call them common sense prudent risk managing principles, maybe they would've been more receptive to the utility proposal. I'm thinking out loud here, maybe some of you have similar ideas.

MR. BRATHWAITE: Well, do you realize, do you realize that you are agreeing with Dale,

that is whole regulatory risk was at issue, not
weather or anything like that?

SPEAKER; Well, I think it --

MR. BRATHWAITE: From your very
statement?

SPEAKER: Well, that's, well, I just
think that these things are obviously
interrelated, because one of the things that I'm
sure the utilities were thinking about when they
requested long-term contracts, that they were very
exposed to the possibility that weather conditions
would put them in the financial hot soup. I'm
seeing some smiles back there.

MR. BRATHWAITE: I am not disagreeing
with you. I am not disagreeing with you, but I am
saying your statement agrees with what Dale is
saying. That's all.

MR. NESBITT: See, what I'm worried
about when you into risk analysis -- oh, go ahead.
I'm sorry.

MR. MELDGIN: I didn't want to get into
any of this debate at all --

(Laughter.)

MR. MELDGIN: But I will say that Dale
mentioned the notion of simultaneously modeling, I

guess, electricity markets in one model. And we've done that at PG&E, and it works, and we'd be happy to share that database with the staff. You'd have to use -- CEC already licenses MarketBuilder, which Dale sells. And we didn't get too far with it, because of the press of other work.

But you can model the simplified version of the North American Gas Grid, like a model of the electric grid all in one model, so that the sort of thing that happened in December 2000 happens right there in one run of the model, and you don't have to change from one model to the next.

SPEAKER: That's an interesting suggestion. Thanks.

MR. FERGUSON: I guess now is the time for me to weigh in. I'm Rich Ferguson from the Center for Energy Efficiency and Renewable Technologies, and follow gas issues for them. And I guess I have to say last spring, I wrote a report which is available on the CEERT Website, which looked at what happened in 2000-2001, and made the prediction that that kind of phenomenon is apt to happen again. So I guess I'll have to use this opportunity to say I told you so.

I have no -- whether looking at weather risk is a good idea or not, I don't know. But the reason I'm here is because the people refer to this renewable portfolio standard, which is a requirement on the utilities, to try and purchase 20 percent of their energy from renewable resources, which would add about ten percent to total supplies because they're already at about ten percent.

In the legislation, there was established this idea of a benchmark price, which is kind of the per se reasonable price that the PUC would accept for these contracts. It is going to be a contentious process at the PUC, I guarantee it. And there are going to be people who are going to go who don't want to buy the renewables, who are going to come in with your $3 gas price and say, well, listen, if we ran that through a plant with a heat rate of 7500 Btu per kilowatt hour, by golly, we've got two and a quarter cent power. So that's the price that we're going to pay for renewables, and not a penny more, and you aren't going to get any.

So it matters. Now, how you figure --

so, if you really believe these, then, okay, then you forget about the portfolio standard because that's not going to happen. And I happen not to believe these prices, and I'd say what's going on in the market today is a pretty good indication that these equilibrium models don't replicate market behavior, and, you know, I, I agree. If I could tell you what the market price was going to be, I would be a rich man. I wouldn't even be bothering to be in here. And we can't do that.

But somehow we've got to try to make some kind of sense of what's going on in the market, and say gee, you know, there's whatever probability you want to assign, that portfolio standard was a prudent move, we should do it, and we should put a, you know, put some proxy price for future gas prices that make those kinds of purchase reasonable.

And, you know, if this goes forward and people who I expect to use it, who will remain unnamed, come in and say, well, you know, the Energy Commission has proven that the gas prices are going to be, you know, $3 for the rest of eternity, and, you know, so we're only going to pay two and a quarter cents, that's a serious problem, you know, for the policy-makers, for my constituents, and a whole lot of people.

So how you get there, you know, I don't know. But we've got to try to understand what's going on in the markets now, and make some judgment about the likelihood of this kind of behavior occurring again in the future to establish some kind of reasonable price that, you know, is going to let us make policy judgments about how much we want to risk increasing demand, how much we want to hedge our risk by buying renewables, and all the rest of the stuff.

Now, I don't know how to do it, I have to admit that running weather scenarios doesn't seem like, doesn't seem like it. You know, I think maybe you ought to get a bunch of market people in here and try to understand what the markets are reacting to now, and judge the likelihood of these situations coming up again.

I have to say, I mean, I'm only a semi-expert on this, I guess, that in my analysis, what happened in 2000-2001 were people were frightened that we were going to run out of storage. And once we got past March in 2001, everybody breathed a sigh of relief and gas went back down to the kind of numbers that come out of these models. And, you know, I think that's what's happening again. Most of us, I think, thought we were going to get through this winter without too much problems, but as of yesterday there were a lot smarter people than I am, talking about $8 gas by the end of this February, and there's a lot of people who think we might run out of storage next winter.

And I think this whole issue of just adequacy of supply and the fear that it might not be adequate is what's driving these prices. Now, how you, what do you do about that in the future, I haven't a clue. But I don't think that what's coming out of these models is a reasonable expectation of what's going to happen in markets, and I have to tell you, if you put that slide out in public, where you have all these prices and they have this huge spike, but in the future that's never going to happen again, you're going to be laughed off the podium.

So, somehow you're going to have to try to integrate what you're doing with the models with what's going on in the markets, and try to make some sense of all this. And I'm happy to help in that process. I don't know how to do it, or I, like I say, I'd be a rich man, I wouldn't be here.

MR. LOGAN: Well, I think we could keep going on for quite a while. Jairam, what's your pleasure?

DR. GOPAL: Are there anymore questions on this topic? Or do you guys want to go home?

(Laughter.)

DR. GOPAL: All right, then. Any questions throughout the day's discussions? It's just an open forum, before we close the workshop. I want to make sure that there are no -- Dale.

MR. NESBITT: There's one other issue I'll bring up, that I know people haven't thought about enough. I've tried to think about it a lot, and I don't know the right answer. That's the retirement of old power plants.

You're seeing in venues like Texas, where the old units haven't been maintained for five years, devaluation of the old rank and cycle units to rates at which we haven't seen in the past are just not going to come back. I'm beginning to believe that that's going to happen, that kind of thing is going to happen everywhere there's rank and cycle power units, including California.

And, you know, I've been kind of, you know, encouraging people like the Commission, go out there and look at life cycle costs on some of these old units. David had it right. I think the demand for incremental entry is a function both of load growth, but more importantly, of these old dogs retiring off the face of the map.

And the analogy I'd like to use, if you think about it, if you were my age, you, when you went to college, you drove yourself a '71 Chevrolet Vega that your dad gave you, and if you were a modern power engineer you'd still be driving it. You'd have to repower it. I mean, heck, an old car is a lot cheaper than a new car, and you've got --

(Laughter.)

MR. NESBITT: You know, and we talk about that '72 Vega that Eisenman's driving all over San Francisco, and he goes down and he fixes the transmission all the time because he's a power engineer type guy, and we all know that old units are better than new units. They never wear out, their costs never go up, they never have thermal stress, you never have to replace the engine, blah, blah, blah. It's ridiculous.

I think we're looking at some significant retirements coming in the state, simply because when you see protracted periods of bad spark spreads, the wheat dies before the straw.

If you asked me what the answer was, I don't know. But the power, you know, we've got about 145 gigawatts rank and cycle units spread around the U.S. You think they're going to last another ten years, given that they're 50 years old? I would bet no. I think it's a big difference in California, for reasons you guys talked about. Location of replacement, that kind of thing.

DR. GOPAL: Any other points, questions, responses? Dave.

MR. MAUL: I'd just like to offer two observations. I've been here at the Energy Commission for 27 years, and lived through power crisis, power plant licensing crisis in local communities, electricity analysis crises, and now a gas crisis. And one, two observations about today's event is that I find that the community folks involved in the gas area seem to be a lot more collegial. We would not have had this kind of an open discussion, a fairly frank discussion, in other areas of the energy markets.

And I really appreciate folks who are willing to speak their mind. You may think you're critical, Dale, occasionally, but don't worry about it. It's stuff that is important that we all want to hear, we want to hear the criticisms of our work, we want to hear the good points of our work. I think our staff has done a very good job in going through the analysis, gathering the data, pulling together and exposing everything we know, strengths and weaknesses both, and we're inviting you to tell us about our strengths and our weaknesses so we can do a better job.

And that gets to the second point, which is part of the Energy Commission's role here in California, is to provide information so that the markets, the participants can all do a better job in this entire environment to work more efficiently. I've seen in the past where a lot of the market participants will hold key information to themselves, and it doesn't allow the markets to work efficiently. We still have to assume that markets will work, and they have to have full information to allow them to work efficiently as they can.

So part of our mission is to provide information, to provide the best, most accurate information that we can, and to provide it to all the parties. And we appreciate you folks that are coming here, telling us about your projects, and we do understand that a lot of you are from a company perspective and may have proprietary information that you'd rather not divulge fully, but to the extent that you can tell us about as much as you can about your projects, their operations, their cost, we can build this into our models and provide information that is of value back to everybody else here, we sure invite your continued participation.

So I'd like to thank each and every one of you for your involvement here today, your participation, and we would certainly like to see you back here again in the future, when we do the next market update.

And with that, Jairam, thank you very much.

DR. GOPAL: I saw some sort of a hint of

closing this workshop from Dale today, so I guess I should continue that step. And now I've got a quiz for you folks.

What is the final date for submission of comments? Oh, there is the winner. Monday, February 3rd. So I want you folks to remember that date and get me those responses. But if you want to spend a little more time in preparing your reports and responses, let me know. That will be welcome, too.

And tune in for the next workshop, that will be in February 25-26.

The NARG model user group meeting that I hold every year will be held at probably in March-April timeframe. I'm trying to juggle what we need to do to get ready for the next forecast, and then we'll hold that one.

And thanks, everyone, for attending this workshop.

(Thereupon, the Staff Workshop on the Natural Gas Supply and Infrastructure Assessment Paper was concluded at 3:50 p.m.)

CERTIFICATE OF REPORTER

I, SCOTT KING, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Staff Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said Workshop, or in any way interested in the outcome of said Workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 2nd day of March, 2003.

SCOTT KING